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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. (U39E)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	A.15-07-002 A.15-07-003 A.15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	A.15-07-005 (Filed July 1, 2015)
And Related Matters.	A.15-07-007 A.15-07-008

DEMONSTRATION PROJECT A AND B PLANS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) PURSUANT TO MAY 2, 2016, ASSIGNED COMMISSIONER'S RULING

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Dated: June 16, 2016

Pursuant to the May 2, 2016, *Assigned Commissioner 's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B* in this proceeding (May 2 ACR), Pacific Gas and Electric Company (PG&E) provides its Project and Implementation Plans for Demonstration Projects A and B as required by the ACR.[1/]

PG&E's Project and Implementation Plans for Demonstration Projects A and B are provided in Attachment A and B respectively.

Respectfully Submitted,

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1/ ACR, pp. 20, 37.

ATTACHMENT A

PG&E Project Plan for Demonstration Project A

Distribution Resource Plan Demonstration Project A – Dynamic Integration Capacity Analysis Project Plan

Executive Summary

This document is a detailed implementation plan for project execution which includes metrics, schedule, and reporting interval. It is based on Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2nd Ruling). The project team will coordinate with the Integration Capacity Analysis (ICA) Working Group as directed to ensure objectives are being met and adjusted as needed from Working Group discussions and recommendations.

Objectives

Below are the objectives as identified in the May 2nd ruling. These objectives are intended to be captured within Demonstration A for learnings to be provided to ICA Working Group.

1.) **Reverse Flow at T&D Interface**
2.) **Effective Locations**
3.) **Incorporate Portfolios and New Technology**
4.) **Consistent Maps and Outputs**
5.) **Computational Efficiency**
6.) **Comparative Analysis**
7.) **Locational Load Shapes**
8.) **Future Roadmap**

Timeline

Task	Date Due
Initiate ICA Working Group	12 May 2016
File Revised Demo A Plan	16 June 2016
Meet monthly to monitor and support Demo A	Q2 – Q4 2016
Execute Tasks on Selected Areas	Q3 2016
Status Report to Working Group on Demo A	01 October 2016
Finalize Results and Comparative Analysis	Q4 2016
Final Report on Demo A	Q4 2016

Demo A Table of Contents

Demo A List of Figures

Plan Requirements from Assigned Commissioner Ruling

PG&E's Project A detailed implementation plan includes the following criteria established by the May 2 Ruling[1]:

a) Documentation of specific and unique project learning objectives for each of the Demonstration A projects, including how the results of the projects are used to inform ICA development and improvement;
b) A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 above, including a process flow chart.
c) A description of the load forecasting or load characterization methodology or tool used to prepare the ICA;
d) Schedule/Gantt chart of the ICA development process for each utility, showing:
    i) Any external (vendor or contract) work required to support it.27
    ii) Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested;
e) Any additional resources required to implement Project A not described in the Applications;
f) A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of the Demonstration A project: 1) an intermediate report; and 2) the final report.
g) Electronic files shall be made available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files;
h) Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy.
i) ORA's proposed twelve (12) criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA.28 Demo A Requirements

PG&E's plan includes all the requirements and is laid out in order as described in this list.

[1] May 2nd Ruling Appendix, pp.17-18.

(A) Demonstration A Learning Objectives

The following learning objectives are pulled from the May 2nd ruling section 2[2] and 3.1[3] of the Appendix. PG&E will explore these learnings within the project to help inform recommendations to be made by the working group to the commission.

1.) **Reverse Flow at T&D Interface[4]:** DER Capacity with and without limiting reverse power beyond substation bus bar. PG&E also wishes to include discussion/consideration of Transmission hosting capacity limitations where possible in the ICA Working Group. This is important as to not overestimate locational transmission reverse flow capabilities without explicitly analyzing within ICA.

2.) **Diverse Locations[5]:** Evaluate two Distribution Planning Areas (DPAs) covering broad range of electrical characteristics and load profiles. PG&E proposes to analyze its Chico and Chowchilla DPAs. These areas range from shorter urban circuits with small amounts of devices and residential loading to longer rural circuits with many devices and industrial/agricultural loading.

3.) **Incorporate Portfolios and New Technology[6]:** Methods for evaluating different DER portfolios and the impact of Smart Inverters. PG&E will evaluate the DER and portfolios listed in the May 2nd Ruling as well as additional DER agreed upon by the ICA Working Group as important to DER development.

4.) **Consistent Maps and Outputs[7]:** Consistent and readable maps to the public with similar data and visual aspects. PG&E will work with the other IOUs and the ICA Working Group to develop an interface that is consistent as well as easy to interpret, based on guidance from the working group as to the needs of the DER community.

5.) **Computational Efficiency[8]:** Evaluate methods for faster and more accurate update process that works for entire service territory. PG&E will assess computational requirements for desired spatial granularity, single phase inclusion, and DER scenario analysis.

6.) **Comparative Analysis[9]:** Benchmark for consistency and validation across techniques and IOUs. As noted in the comparative analysis section, PDG&E will be running multiple analyses to compare both methodologies on its own system, as well as with the other IOUs for consistency of results.

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[2] May 2nd Ruling Appendix, pp. 15-18
[3] May 2nd Ruling Appendix, pp. 19-20
[4] May 2nd Ruling Appendix, pp. 15 “Demonstration Project A Power Flow Scenarios” Section
[5] May 2nd Ruling Appendix, pp. 16 “Demonstration A Project Locations” Section
[6] May 2nd Ruling Appendix, pp. 19 list item ‘b’
[7] May 2nd Ruling Appendix, pp. 19 list item ‘c’
[8] May 2nd Ruling Appendix, pp. 19 list item ‘d’
[9] May 2nd Ruling Appendix, pp. 19 list item ‘e’

7.) **Locational Load Shapes[10]:** Utilize Smart Meters for localized load shapes, which include at a minimum peak and minimum load shapes

8.) **Future Roadmap[11]:** Determine roadmap and timelines for future ICA achievements based on demonstration learnings. Through the ICA working group, PG&E will collaboratively review and develop recommendations for future ICA improvements.

These objectives were pulled in order as mentioned in the ruling as specific objectives for the Demonstration A project. The following sections below will describe these in more detail and along with schedule to complete.

[10] May 2nd Ruling Appendix, pp. 19 list item ‘f’.
[11] May 2nd Ruling Appendix, pp. 20 list item ‘g’.

(B) ICA Baseline Requirements and Conformance

A. Baseline Methodology and Modifications

The PG&E Integration Capacity Analysis (ICA) methodology in the Demonstration A project will strive to meet the modified baseline methodology as specified in the Assigned Commissioner Ruling on May 2nd. This section will explain how PG&E will meet these requirements. The baseline methodology had these specifications:

Baseline Methodology Steps[12]

1. Establish distribution system level of granularity
2. Model and Extract Power System Data
3. Evaluate Power System Criterion to determine DER capacity
4. Calculate ICA results and display on online map

Modifications to Include in the Baseline[13]

1. Qualify the Capability of the Distribution System to Host DER
2. Common Methodology Across all IOUs
3. Different Types of DER
4. Granularity of ICA in Distribution System
5. Thermal Ratings, Protection Limits, Power Quality (including voltage), and Safety Standards
6. Publish the Results via Online Maps
7. Time Series or Dynamic Models

The following are brief descriptions relating to sub bullet items within the modifications listing on pages 9-15 of how these are being met in PG&E's Demonstration A (Demo A) Project.

<u>Baseline Methodology Steps</u>

1. **Establish distribution system level of granularity**
   - PG&E's initial filing complied with guidance to perform analysis and achieve results granular down to the line section and node level. Nodes were isolated for computational efficiency, but the Demo A project will explore analysis at all nodes in the system.

2. **Model and Extract Power System Data**
   - CYMDIST is utilized for geospatial circuit models with all necessary components down to the primary side of the customer service transformers.[14]
   - LoadSEER is utilized for forecasting and modeling of load profiles across the system to the proper hourly granularity as required by the May 2nd Ruling.[15]

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[12] May 2nd Ruling Appendix, pp. 6-9 "Overview of Baseline ICA Methodology Steps" Section.
[13] May 2nd Ruling Appendix, pp. 9-15 "Specific Modifications to Include in Baseline Methodology" Section.
[14] May 2nd Ruling Appendix, pp. 6-7 Items 1 and 2 in "Overview of Baseline ICA Methodology Steps."

3. **Evaluate Power System Criterion to determine DER capacity**
    - Four major criterion of Thermal, Protection, Power Quality/Voltage, and Safety/Reliability were considered and analyzed in the analysis. The demo project will look to ensure components in Table 2-4 of PG&E DRP are being included were practicable and the accuracy of such analysis is validated.

4. **Calculate ICA results and display on online map**
    - Results across the different layers of the system (i.e. line section, feeder, substation transformer) are extracted from the analysis and published to the online RAM map. Knowing results of different layers can help inform smaller scale retail developers as well as larger scale wholesale developers.

<u>Modifications to Include in the Baseline</u>

1. **Qualify the Capability of the Distribution system to Host DER**
    a. Electric distribution feeders (a.k.a. Circuits) are modeled in CYMDIST with the individual capacitor bank devices that contribute reactive power to the circuit.
    b. Utilizing an analysis structure not solely based in the power flow models allows for expanded analysis across multiple feeders connected on the same substation transformers. This assists in the expanded analysis since the CYMDIST modeling only models to the circuit breaker of the feeder. PG&E's recent conversion to a new GIS platform is allowing for possible expanding modeling directly in the CYMDIST models and will be explored for feasibility in Demo A.
    c. Effects of load modifying resources (i.e. Energy Efficiency and Demand Response) can be explored in two ways. The first method for reflecting the effect of potential load modifying resources for ICA is to examine the "net" loading effect of load modifying resources which will change the loading conditions to which ICA is calculated. The second is by considering these load modifying resources as a virtual generator directly analyzed with ICA. At a minimum the first will be explored and the second provided desire and input from the ICAWG.
    d. Assumptions will be provided in the required report to help inform ICAWG on how ICA is considering distribution system conditions and DER parameters

2. **Common Methodology Across all IOUs**
    a. Through comparative assessment and coordination with the ICA Working Group the three IOUs will work together for more consistency in ICA as outlined in the ACR.

3. **Different Types of DER**
    a. The ACR outlined a set of 'typical' DER profiles to consider in the analysis. PG&E has already provided ability to do so and will coordinate consistency with other IOUs.

[15] May 2nd Ruling Appendix, pp. 7 "Model and Extract Power System Data" Section.

b. PG&E will explore with the ICA Working Group other DER portfolios and resource types as prescribed by the ACR.
c. Discussions with ICA Working Group will require selection of 'typical' and/or baseline portfolios given amount of possible portfolios mixes and combinations. Computational efficiency improvements are also being evaluated to aide in this objective.
d. Coordination with the ICA Working Group will be needed to identify which other DER portfolio combinations are to be considered in the analysis.

4. Granularity of ICA in Distribution System

a. The granularity of the ICA will be at a line section and/or node level on the primary distribution system as per the original guidance and the May 2nd ACR. This means that ICA will be analyzed for the high voltage (4 kV to 21 kV) side of the distribution system. Scope of the analysis will not include the service transformers or secondary service to customer premises.

5. Thermal Ratings, Protection Limits, Power Quality (including voltage), and Safety Standards

a. Four major criterion of Thermal, Protection, Power Quality/Voltage, and Safety/Reliability were considered and analyzed in the analysis. The demo project will look to ensure components in Table 2-4 of PG&E DRP are being included were practicable and the accuracy of such analysis is validated.
b. Protection impacts and limits will be evaluated with coordination between IOUs on where increased consistency can be achieved. For instance, exploring evaluating both Short Circuit Capability as well as Reduction of Reach versus IOUs evaluating only one or the other.
c. Including in the reporting to the ICA Working Group will be documentation of the limit criteria and thresholds used in the analysis. This will be in the Q3 intermediate status report in 2016.
d. Included in this report will be identification of any federal, state, and industry standards embedded within the ICA criterion.
e. Extraneous data will be explored for inclusion with the ICA results which would be an expansion of the data provided as part of the RAM map. This would be data such as feeder level loading and voltage, customer type breakdown, and existing DER. This will have to coordinate with data discussions in the ICA Working Group to ensure proper customer privacy is not violated.
f. Identification of feeders on which this data would not comply with customer privacy rules. For instance if the load data provided for a circuit in which there are less than 100 residential customers and/or 15 non-residential customers.
g. As discussed in the ICA Workshop in November 2015, PG&E will explore the ability to provide a detailed breakdown of the various constraints limiting the hosting capacity on its circuits. The exploration will be two fold with (1) exploration of hourly ICA profiles versus single point constraints limited by minimum values and (2) exploration of categorical limitations versus single point overall limitation. These two components should aid users in understanding the

type, frequency, timing, and duration of ICA limitations for developing optimized portfolios to increase penetration of DER with limited system impact.

6. **Publish the Results via Online Maps**
    a. Currently PG&E's ICA results are published in coordination with PG&E RAM map. ICA results and load profiles are also published and available on the Commission's DRP webpage. One of the major objectives of this demo is to gain further alignment with the online maps for which ICA is displayed. ICA Working Group coordination and input will be desired to drive consistent and effective display of data. Downloadable format and mechanism discussions shall also be performed and coordination with the ICA Working Group.
    b. The information originally provided by in the RAM map has much overlap with the DRP ICA data. It will be the intention that the original data of RAM is the default information provided and that ICA data is properly coordinated. This will include reviewing and reducing overlap of new data and making sure interface is user friendly and effective for developers.

7. **Time Series or Dynamic Models**
    a. PG&E's initial filing included time-series analysis and power flow evaluation. The demo project will explore including, at a minimum[16], peak and minimum 24 hour profiles for each month as well as dynamic power flow interactions with time-dependent components of the system. This is a major application of exploration of various approaches such as iterative simulation and streamlined calculation. The demo project will explore most feasible path forward that also strives to ensure consistency between all IOUs.

Based on the ACR and ICA working group discussions there will be limitations within the Demonstration A Project with respect to secondary voltage service analysis and high voltage transmission line analysis. These parts of the system are on either side of the primary distribution system which delivers power to the end users at voltages between 4kV and 21kV. Discussion of analysis for these parts of the system can be explored in the ICA Working Group for long term vision, but will be out of scope for the demonstration project. Transmission system limitations and analysis would be a good topic of discussion since the demonstration project will be evaluating reverse flow into the transmission system without consideration of locational transmission system constraints. However, for the scope of this demonstration, obtaining specific results for the transmission system limitations are out of scope. Below is a visual depiction of items in and out of scope for Demonstration A.

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[16] May 2nd Ruling Appendix, pp. 7 list item '2'.

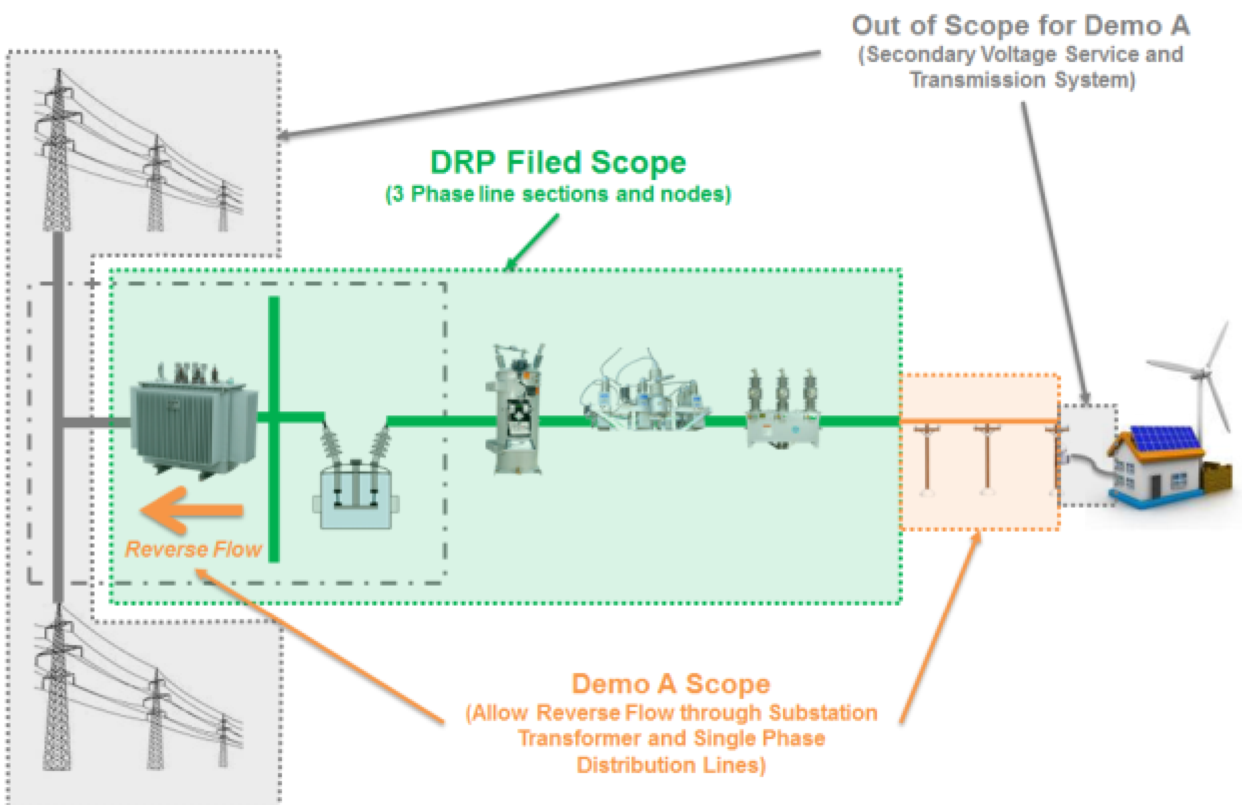


Figure 1 – Simplified Depiction of System Scope for Demonstration A

B. Baseline Methodology Steps

The baseline methodology as described in the ACR includes 4 steps to evaluating the host capacity of a distribution circuit or substation. PG&E's methodology conforms to these four steps, as described below. Utilizing Demo A and EPIC 2.23, PG&E will perform the ICA using the streamlined and iterative methods to compare methods for accuracy, flexibility, and speed of computation while meeting requirements of the Mar 2nd Ruling and recommendations of the ICA Working Group.

1. Establish distribution system level of granularity

The first step in ICA is to have a detailed circuit model and data. CYMDIST imports from Geographic Information System (GIS) facilities data. The figure below illustrates the geospatial nature of the distribution feeders and how they are mapped in the PG&E asset database.

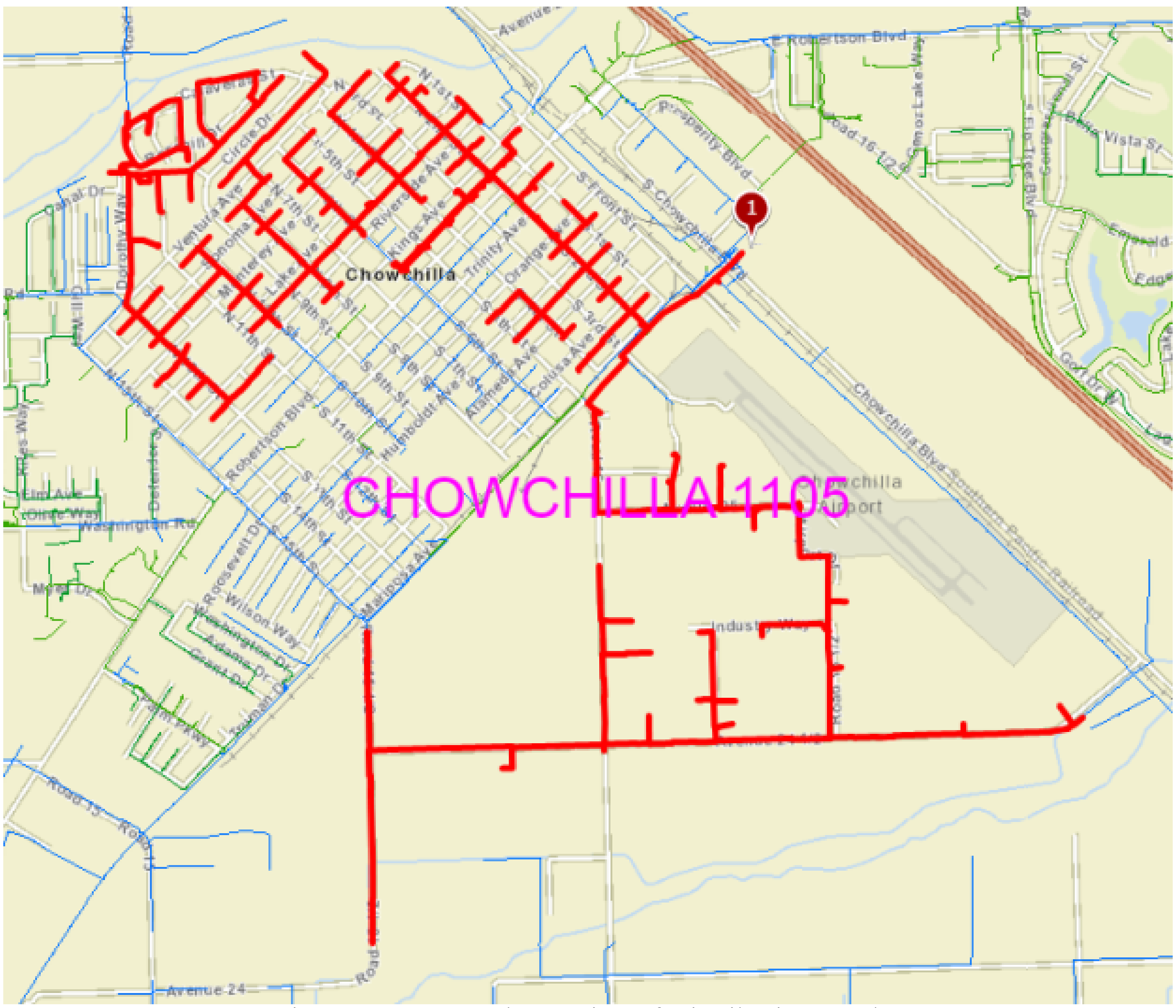


Figure 2 - GIS Tool Mapping of Distribution Feeder

The extracted data from GIS are the type and length of the conductor, type of switch, structures and subsurface equipment, reclosers, sectionalizers, fuses, capacitors, voltage regulators, generators, service transformer loads, etc.

This detailed data allows for a high level of granularity to accomplish an analysis of each line segment. In the GIS model, a line segment represents an electrical path between two points or nodes. A node can be roughly defined as a pole or underground structure. The analysis will be applied to all the line segments on the main feeder and branches including three phase and single phase lines. Refer to the figure below for a display of the same feeder extracted into the power flow tool. For visual purposes the three phase lines were colored in blue and single phase lines were colored in orange. A few devices such as fuses, reclosers, and capacitors were circled as well for reference.

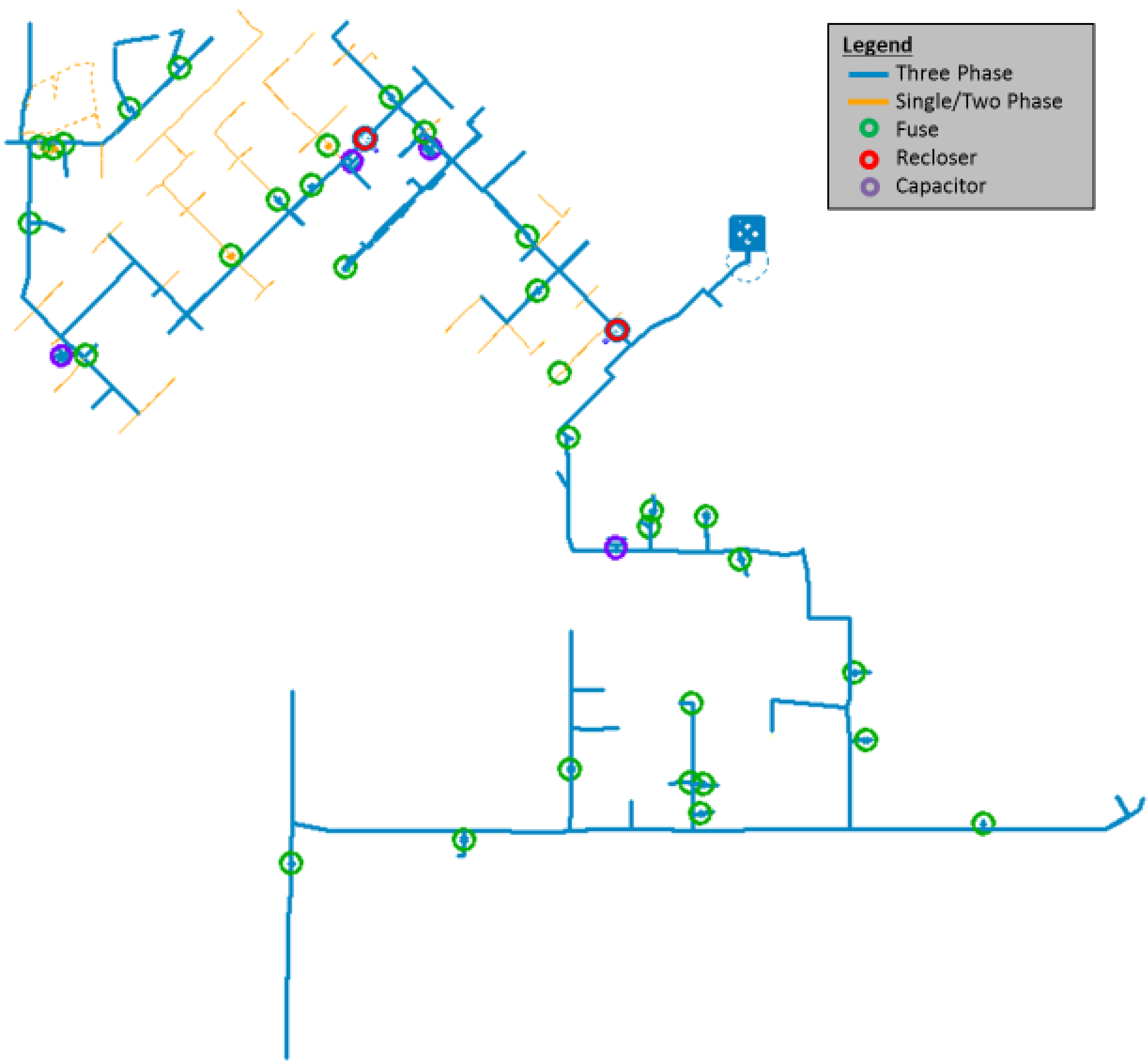


Figure 3 – Power Flow Model Highlighting Key Devices and Single Phase Lines

2. Model and extract power system data

PG&E uses a power flow simulation tool to assist in the ICA process. This approach performs power flow analysis on the circuit model using CYMDIST. The analysis will be conducted on each line segment and/or customer load up to the substation circuit breaker. The following information databases are used to build the circuit models as shown in Figure 3.

- **Electric Distribution Geographic Information System (EDGIS):** The circuit model is built from detailed data, as described in level of granularity. It contains the thermal ratings for conductors and devices, device and equipment characteristics, and load and generation customer details.

- **LoadSEER:** Load profiles and forecast information that can be applied to the feeder loads and generation.

- **Supervisory Control and Data Acquisition (SCADA):** SCADA data is leveraged by LoadSEER to develop the demand profile for each circuit, which is then aggregated up to the substation bus.

- **Advanced Metering Infrastructure (AMI):** Interval metered data is extracted for the customers on every circuit and load is allocated to the circuit model and utilized in LoadSEER for profile evaluation.

Once the circuit models are built, AMI data and LoadSEER are used to develop demand curves for each circuit based on customer class and historical data. LoadSEER develops curves from SCADA data, while AMI data is used to allocate the demand data to each service transformer appropriately.

3. Evaluate Power System Criteria to Determine DER Capacity

CYMDIST and LoadSEER will be used to evaluate power system criteria on the circuit model to determined DER capacity limits on each distribution circuit. As required by the ACR[17], four general power system criteria were used in the ICA to determine the hosting capacity for DER. The ACR instructs the utilities, as part of Demonstration Project A, to incorporate the list of analyses from PG&E's table 2-4 in its DRP filing to the extent feasible[18]. PG&E has modified to the table to provide the detailed criteria that will be evaluated as part of Demonstration Project A, and what remains as potential future analysis to be evaluated. This modified table is below.

[17] May 2nd Ruling Appendix, pp. 7-9 Section "Evaluate power system criterion to determine DER capacity."
[18] May 2nd Ruling Appendix, pp. 12 list item '5.a'.

Table 1 – Power System Criterion Scope of Work

Power System Criteria	Demonstration A Analysis	Potential Future Analysis
Thermal		
Substation Transformer	X	X
Circuit Breaker	X	X
Primary Conductor	X	X
Main Line Device	X	X
Tap Line device	X	X
Service Transformer		X
Secondary Conductor		X
Transmission Line		X
Voltage/Power Quality		
Transient Voltage	X	X
Steady State Voltage	X	X
Voltage Regulator Impact		X
Substation Load tap Changer Impact		X
Harmonic Resonance/ Distortion		X
Transmission Voltage Impact		X
Protection		
Line Equipment Interrupter Capability	X	X
Protective Relay Reduction of Reach	X	X
Fuse Coordination		X
Sympathetic Tripping		X
Transmission Protection		X
Safety/Reliability		
Islanding / Out of Phase Reclosing	X	X
Transmission Penetration	X	X
Operational Flexibility	X	X
Transmission System Frequency		X
Transmission System Recovery		X

4. Calculate ICA results and display on online map

Each criteria limit is calculated for the most limiting value and is used to establish the integration capacity limit. The following is a simplified diagram of how the two techniques fit into the overall framework of the methodology to determine ICA results.

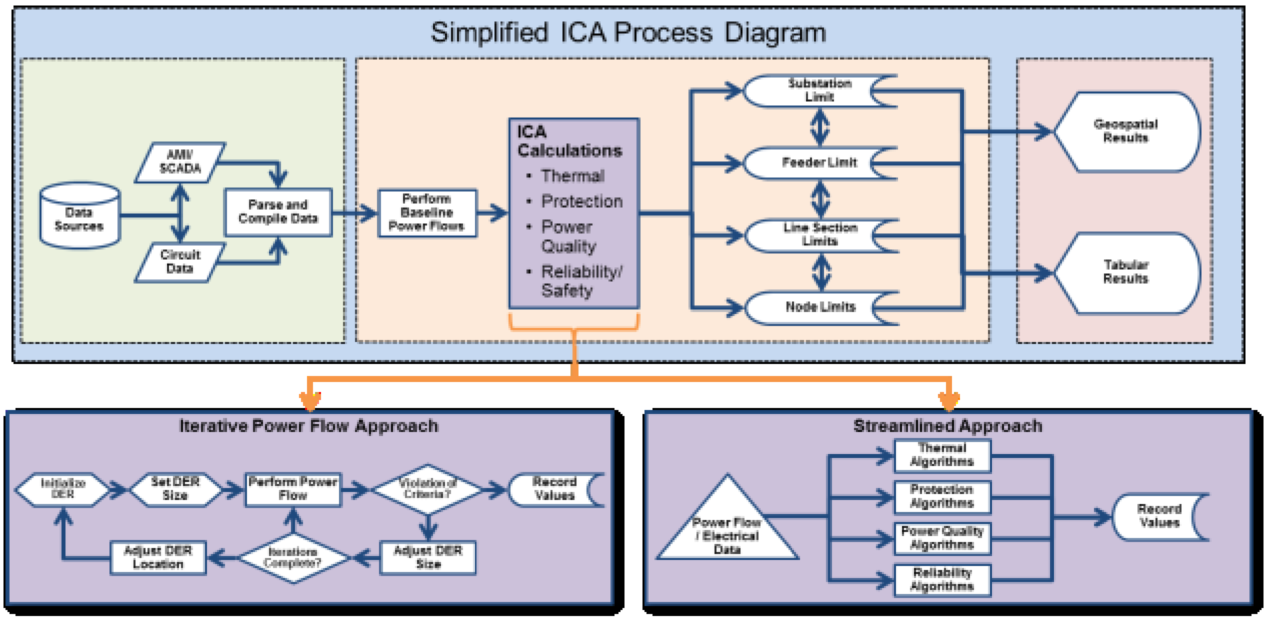


Figure 4 - Simplified ICA Methodology Diagram

The resulting ICA data will be publicly available using the Renewable Auction Mechanism (RAM) Program Map. The ICA maps will be available online and will provide a user with access to the results of the ICA by clicking on the map. The map will be characterized as a “Heat Map” colored by range of DER as agreed upon by the IOUs and ICA Working Group. The figure below shows and example of what a heat map could look like.

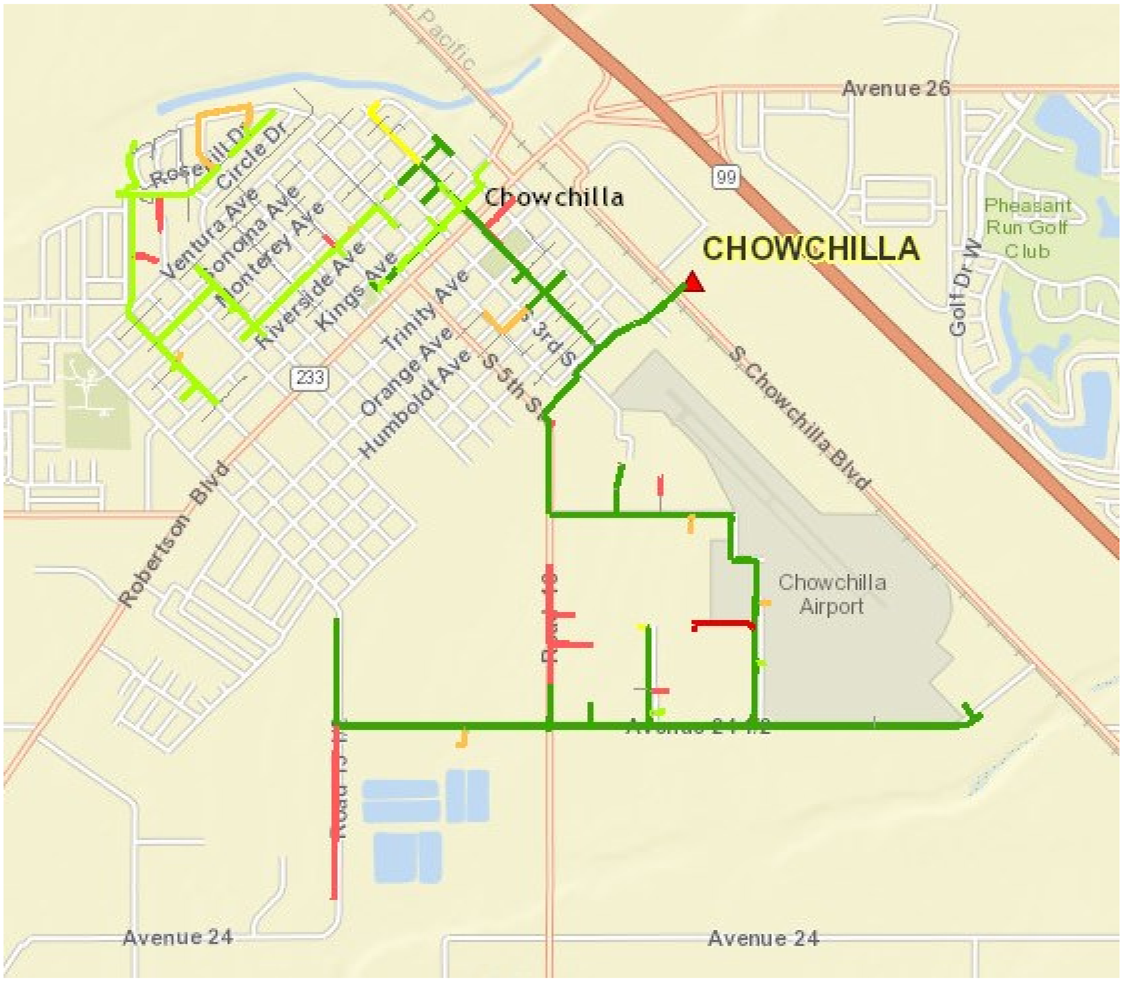
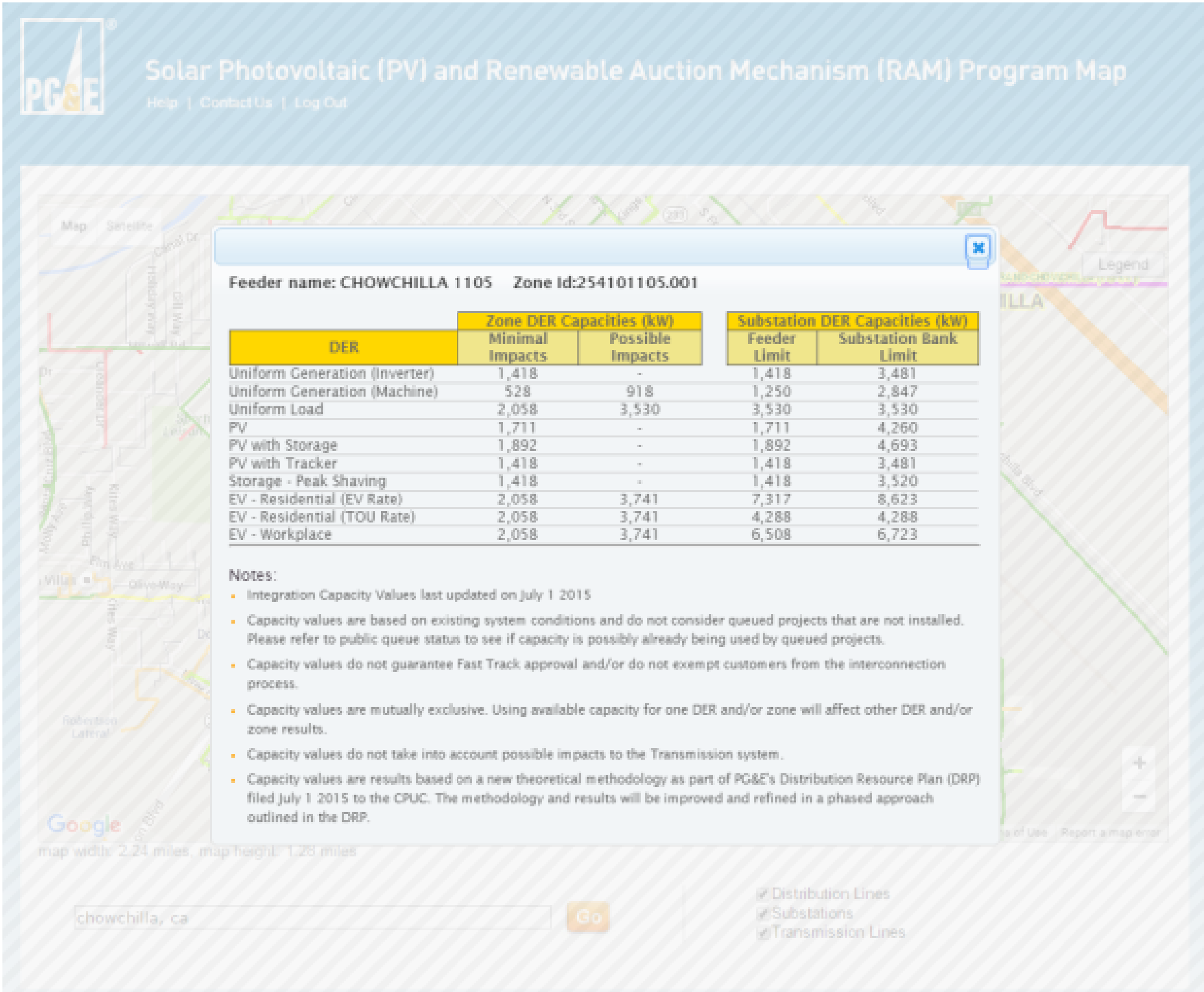


Figure 5 - Heat Map Example

The line segment could provide capacity for various DER types as required by the ACR. Capacity limits will be displayed on the RAM maps by clicking on the line segment. The call out box will display the available capacity limit at the line segment, feeder and substation transformer. The IOUs along with the ICA Working Group will decide on a common display for ease of understanding. Below is an example of how PG&E's current RAM map displays these DER specific values. This may change based on input and discussion with the ICA Working Group.



DER	Zone DER Capacities (kW)		Substation DER Capacities (kW)	
	Minimal Impacts	Possible Impacts	Feeder Limit	Substation Bank Limit
Uniform Generation (Inverter)	1,418	-	1,418	3,481
Uniform Generation (Machine)	528	918	1,250	2,847
Uniform Load	2,058	3,530	3,530	3,530
PV	1,711	-	1,711	4,260
PV with Storage	1,892	-	1,892	4,693
PV with Tracker	1,418	-	1,418	3,481
Storage - Peak Shaving	1,418	-	1,418	3,520
EV - Residential (EV Rate)	2,058	3,741	7,317	8,623
EV - Residential (TOU Rate)	2,058	3,741	4,288	4,288
EV - Workplace	2,058	3,741	6,508	6,723

Figure 6 - Example of DER Specific ICA Currently on PG&E's RAM Map

The ACR requires two aspects of time horizon and growth scenarios to be considered for the final results as well.[19] While the base with no DER growth will be considered for base assessment and comparison, the scenarios as outlined will also be considered. The two aspects of consideration are:

1. 2-year growth scenario
2. Growth scenarios 1 and 3 as proposed in the DRP Applications

Specific comparison formats and approach can be discussed with the ICA Working Group as the project progresses and data is analyzed.

[19] May 2nd Ruling Appendix, pp. 4-5, Section "Discussion of Section 1.a.ii of the ICA Guidance".

C. ICA Working Group Recommendation on Baseline Methodology

The following is the recommendation of the Integration Capacity Analysis Working Group (ICAWG) that recommended slight modification to the ACR to allow more flexibility in demonstrating various calculations techniques in the methodology.[20] The recommendation was as follows:

> *ICA WG supports the Joint IOU request to test both the streamline and iterative methods through the Demo A projects to help inform adoption of the best single ICA method or combination of comparable methods, consistent with the ACR timeline, for all IOUs to use going forward. SCE and PG&E will test both methods and the ICA WG will reach consensus on whether SDG&E will also test both methods at the next meeting. Using these different methods, the Demo A will enable the following:*
>
> - *Results allow for streamlined Rule 21 interconnections while also informing developers and customers where DER and combinations of DER are best deployed*
> - *Scenario analysis across the whole grid, in a timely manner, to inform planning for hosting capacity*
> - *Methodology is flexible enough to model different DER types and DER portfolios*
>
> *However, this support is conditioned on the IOU Demo A plans including detailed plans for a comparative assessment of the two methods by the IOUs and to identify the process for moving toward a single methodology (or combination of methods that are determined to be comparable) statewide once the results of the Demonstration Projects are known. The Demo A plans, consistent with the ACR (p.19, 3.1.d & e), should include the following:*
>
> 1. *A detailed comparative summary of the methodologies and the content and format of results from the ICA analyses to be performed through Demo A projects.*
> 2. *A detailed common comparative evaluation explaining how results of the individual IOU Demo A projects will be analyzed to allow comparison of: a) ICA accuracy; b) ICA consistency; c) incremental ICA computing needs and costs; d) ICA computing time; e) ability to model both different types of DERs and DER portfolios, as well as different scenarios system wide.*
> 3. *Recommended protocol for baseline tests using reference circuits, for discussion and approval by the ICA working group. The baseline testing should test the full range of circuits, projected loads, and DER penetration across IOUs, and will test each individual ICA criteria (e.g., thermal, protection, power quality, safety). Testing on a single sample circuit will not be sufficient to demonstrate compliance with the CPUC requirement for consistency.*
> 4. *Discussion of how working group input regarding optimal granularity and frequency of updates will be incorporated in the Demo A projects.*

[20] http://drpwg.org/, "FINAL Consensus Recommendation of ICA WG completed at June 1st meeting & submitted to CPUC".

5. *A process for publishing the details of the methodologies, testing their consistency, and results should include reviews by the ICA WG prior to being submitted to the CPUC.*
6. *A process for not only testing the speed and accuracy of both methods, but also identifying improvements to the results of each method.*
7. *Use outside resources (e.g. EPRI work) as a starting point for developing and evaluating each method, where possible.*

[End of ICA Working Group Recommendation]

The purpose of the pilots and Demonstration A is to test/evaluate enhancements to ICA. To further enhance innovation the ICA working Group supported the Joint Utilities request to use the following two calculation techniques:

1.) **Streamlined Calculations:** Calculating limits with streamlined calculations/algorithms informed by baseline power flow, electrical circuit characteristics, and load profiles
2.) **Iterative Simulation:** Recording limits based on violations observed using iterative resource placement and power flows

Based on PG&E's understanding, there are various use cases where the Streamlined Calculation method serves certain needs well. Conversely, there are other uses cases where the Iterative Simulation method serves other needs well. Moreover, when multiple methods return similar results, we have increased confidence (triangulation / convergent validity).

Convergent validity is important due to the multiple use cases that ICA will serve in the future. ICA will be needed for the system planning of additional DER hosting capacity and for the streamlined interconnection of DERs

EPRI has declared in their 2015 report '*A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources*' that streamlined approaches can be used in interconnection.[21] PG&E has already benchmarked with their method and has realized many similarities in the streamlined approaches as used in the initial 2015 filing. PG&E would like additional benchmarking for validation of techniques to ensure best solution going forward that is practicable for the PG&E system. PG&E proposes to perform benchmark comparison of "detailed" versus "streamlined" in similar fashion as EPRI. This is intended to determine if similar conclusions as EPRI can be made for more confidence in applying streamlined ICA to further streamline CA Rule 21 interconnection.

PG&E is exploring both detailed/iterative and streamlined approaches within its EPIC 2.23 and the Demonstration A projects. PG&E is uncertain of the processing requirements necessary to run detailed approach across PG&E's roughly 3,000 detailed circuit models. The EPIC project will shed light on specific processing requirements that may be needed for detailed approach to meet use case scope of ICA (i.e multiple hours, multiple DER types, substation, single phase,

[21] *A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources: A Streamlined Approach for Solar Photovoltaics.* EPRI, Palo Alto, CA: 2014. 3002003278.

portfolios) . As requested by ruling, PG&E will explore the computational efficiencies in this demo project to help answer this question. PG&E will explore a blended approach in which both methods are utilized to increase confidence, reduce processing times, and meet multiple use cases.

D. Distribution Planning Areas Selection

Demonstration A project locations proposed in the Applications are modified and shall include two Distribution Planning Areas (DPAs) that cover as broad a range as possible of electrical characteristics encountered in the respective IOU systems (e.g., one rural DPA and one urban DPA). The IOUs shall clarify if their originally proposed Demonstration A project locations satisfies one of the two required DPAs and what their other proposed DPA(s) are. The IOUs shall also justify in their detailed plans the basis for choosing each DPA for the Demonstration Projects.

The two DPAs that are proposed to be evaluated are:

1) Chico (Urban/Suburban)
2) Chowchilla (Rural)

The locations within PG&E territory are shown in the figure below with Chico circled in Blue and Chowchilla circled in Red. The rest of this section explains the differences of the two DPAs and the electrical characteristic variation.

Figure 7 - Selected DPA Locations for Demonstration A

These two DPAs represent one urban/suburban and one rural DPA within the PG&E territory. The intent of picking a DPA from each of these categories is to get varying characteristics in which to evaluate varying conditions in the system. The other goal is to drive coordinated learnings with the other Demonstration Projects B and C. This led to the selection of the Chico and Chowchilla DPAs. Evaluation of the characteristic variation was performed to see if they were sufficiently diverse across the included feeders. That evaluation is below. Here is some general information about the DPAs:

	Chico	**Chowchilla**
Location	Butte County (Urban/Suburban)	Madera County (Rural)
Substations	10	4
Feeders	37 - 12 kV, 4 - 4 kV	20 - 12 kV
Customers	125,000	13,000
Recent Historical Peak	235 MW	155 MW
Customer Type	80% Residential, 5% Agricultural, 15% Commercial & Industrial	60% Residential, 30% Agricultural, 10% Commercial & Industrial

The following is the analysis performed to understand the electrical diversity in the feeders within the two DPAs. The group of figures below depicts statistical variation of characteristics for each feeder within the group set. The group sets are:

- **"System"** – All distribution feeders
- **"Chico"** – Only feeders in Chico DPA
- **"Chowchilla"** – Only feeders in Chowchilla DPA

The electrical characteristics evaluated are:

- **Total Length of Circuit** – This is the summation of all the line length for each line on the feeder and is important to understand how ICA manages shorter circuits versus longer circuits
- **Maximum 3-phase Resistance** – This is the maximum resistance of the three phase line section which helps determine the range of possible worst case resistance a circuit can provide DERs.
- **Voltage Regulator Count** – The amount of regulators helps understand the complexity of voltage management on the circuits. Smaller counts mean easier voltage management and larger means more complex management of voltage.
- **Capacitors** – The amount of reactive support provided by capacitors on the circuit to reduce losses and help voltage. More capacitors mean more complex voltage management and more possible losses on the circuit.
- **Protective Recloser Count** – The recloser count will help provide possible complexity of protection schemes on a circuit. The more reclosers the easier it may be for a DER to impact the protection coordination on the circuit.

The statistical variation is shown with box and whisker charts to show the distribution and range of each characteristic between the groups. With these two DPAs it can be seen that a majority of the ranges of these characteristics are covered. The first three quartile ranges are covered across these categories as well as a majority of the 4th quartile. It is through this analysis that PG&E is confident that these DPAs provide the required "broad range" of electrical characteristics required by the ACR.

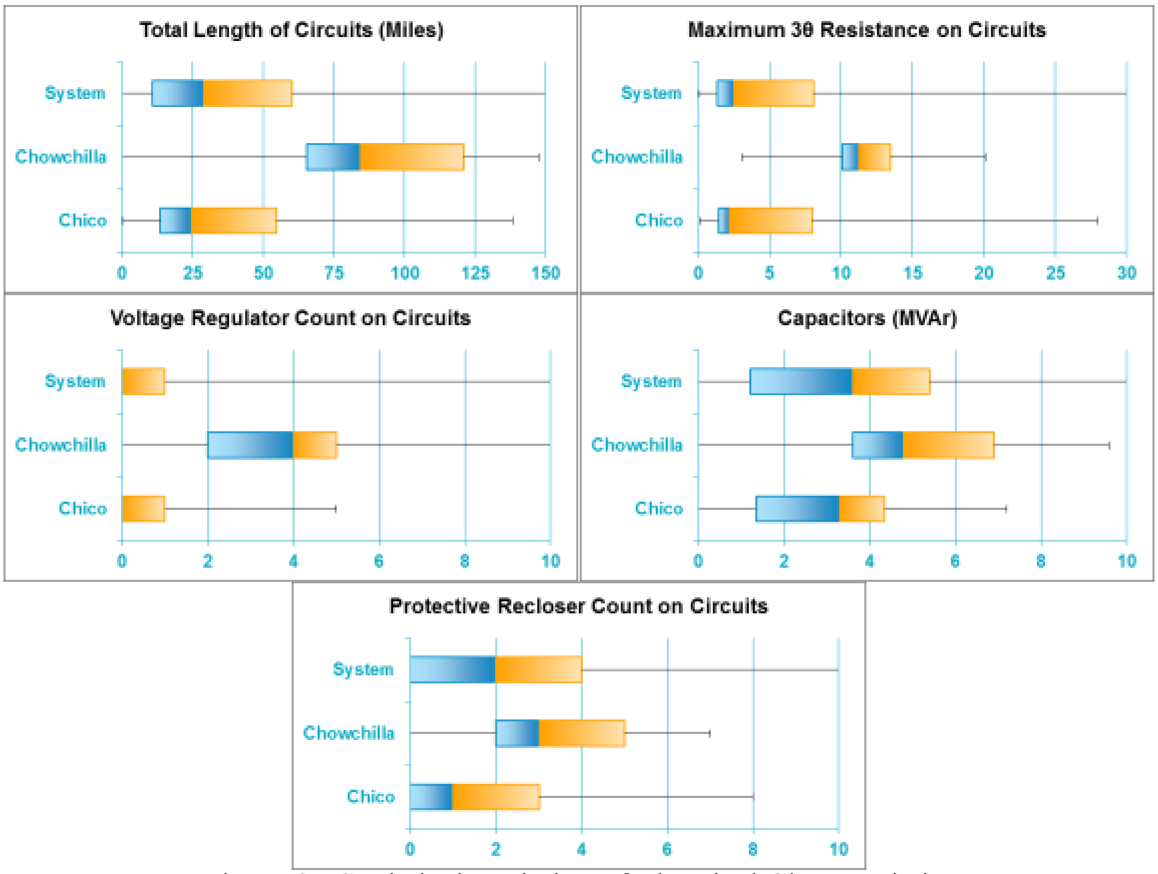


Figure 8 - Statistical Variation of Electrical Characteristics

A load profile variation analysis was performed on the two DPAs. This analysis used some of the preliminary enhanced load profile data within the EPIC 2.23 project. These load profiles are aggregated profiles for each DPA which is built on hourly meter data for the customers within the DPAs. The different percentile shapes show the probability of hourly load throughout the year as a percentage of the peak. Chico is representative of typical residential loading with summer peaking driven by temperature. Variation between the tight bands in the winter versus the wider bands in the summer will be good for analysis. Chowchilla is representative of rural loading driven by non-residential load. This area is good for analysis to understand the low loading times which would push more reverse flow from generating DERs. These profiles can be seen in the figures below.

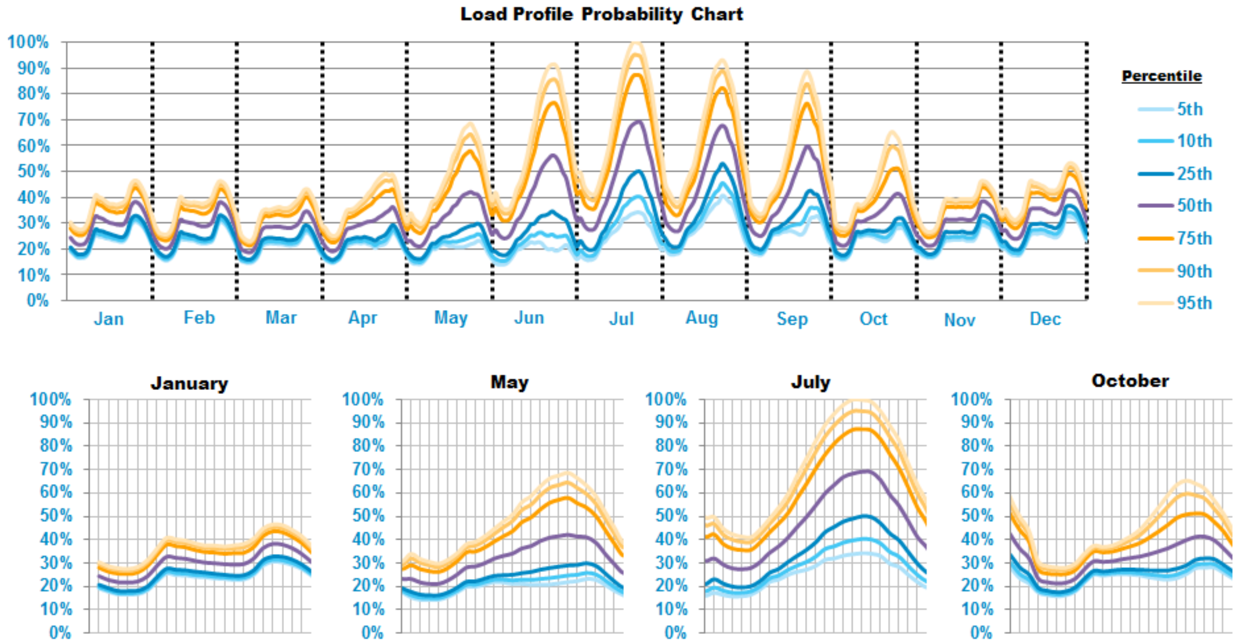


Figure 9 - Chico Load Profile Variance

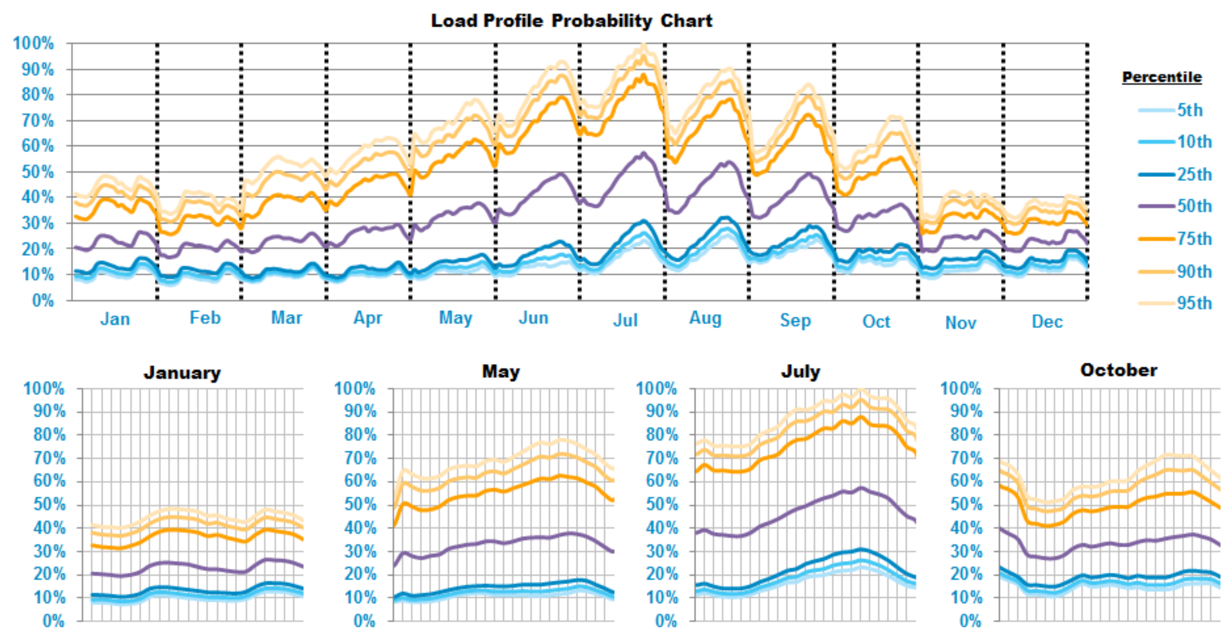


Figure 10 - Chowchilla Load Profile Variation

(C) Tools Used to Prepare ICA

PG&E will be utilizing its two main planning tools for this demonstration project:

1.) **CYMDIST:** the Power Flow Analysis Tool used to model and update distribution systems including but not limited to conductors/cables, line devices, loads and generation components and to perform iterative load flow analyses in order to identify the DER hosting capacity.
2.) **Python:** the dynamic object-oriented programming tool used to automate both the streamlined method and the iterative method as well as perform data analysis within the CYMDIST software
3.) **LoadSEER:** the load forecasting analysis tool used to develop electric distribution forecasts and locational demand profiles throughout the system
4.) **SQL:** the informational management tool used for ICA results repository and post simulation analysis. The use of this tool independently may be phased out given level of incorporation into other tools
5.) **ESRI ArcDesktop:** the maps and geographic information tool used for creation of the geospatial ICA results visualization on the PG&E RAM map
6.) **Microsoft Office Suites:** general data process tools such as Excel and Access used for relevant post processing

While specific components developed for demonstration project A may not be available in the commercial product, it is PG&E intention to move away from customized databases as much as possible and allow for integration into commercially available tools. At a minimum and subject to vendor trade secrets / proprietary methods, details of methodologies and implementation into the tools will be discussed through the ICA Working Group. The following will provide more detail about the two major tools used for the analysis which will be CYMDIST and LoadSEER

E. CYMDIST by CYME International

The CYMDIST Distribution Analysis software is a suite of applications composed of a network editor, analysis modules and user-customizable model libraries from which you can choose to get the most powerful solution. The program is designed for planning studies and simulating the behavior of electrical distribution networks under different operating conditions and scenarios. It includes several built-in functions that are required for distribution network planning, operation and analysis. Innovative engineering technologies, industry practices and standards are at the core of the CYMDIST algorithms, flexible user interface and extensive libraries.[22]

This tool is primarily used to understand the power flow and electrical characteristics of the distribution system. PG&E models each of its distribution feeders using a conversion tool to translate Geographical Information System (GIS) mapping data into CYMDIST circuit model database. Similar to how SCADA improves power profiling, Geographic Information System (GIS) mapping improves the ability for PG&E to more accurately analyze impacts on its system assets. CYMDIST analyzes power flow on distribution feeders by modeling conductors, line devices, loads, and generation to determine impacts on distribution circuit level power quality

[22] http://www.cyme.com/software/cymdist/.

and reliability. GIS mapping traces the distribution system down to the service transformer level. Knowing the composition of a particular series of line conductors as well as their relative location from a power source allows engineers to determine impedance to a specific location on the distribution feeder. These electrical models are updated weekly to reflect changes that occur on PG&E's distribution system. This is distinct from power flow models that validate load flows and planning forecasts, which are updated seasonally.

ICA techniques utilize batch processing capabilities of CYMDIST which require python scripting to implement. This open architecture allows specific scripts to fit the needs of the new ICA techniques. These capabilities are the foundation of the EPIC 2.23 project that allow for PG&E to explore integrating the two tools and explore the new techniques required to calculate ICA.

F. LoadSEER by Integral Analytics

LoadSEER 's powerful GIS mapping and load forecasting functionality uniquely blends short term circuit forecasting with long term spatial forecasting, enabling distribution planners to more accurately predict risks on their circuits due to acre-level load growth and/or distributed generation changes, including electric vehicle adoption, increasing solar penetration, switching transfers, economic trends and other factors. This enables PG&E to analyze specific circuit by circuit analysis of which econometric drivers are driving the growth and risk for each circuit.[23]

Utilizing this tool, PG&E's Distribution Planning Process has transitioned from planning based on singular peak values to planning based on representative hourly power profiles. To develop power profiles, PG&E uses LoadSEER which takes hourly customer load and generation profiles and aggregates them to determine power profiles at the feeder, substation and system levels. This tool is also used to determine distribution forecast impacts due to forecasted load growth.

To collect customer usage data PG&E uses SmartMeters™, which capture energy usage data on regular intervals 24 hours a day, 7 days a week. SmartMeters™ have been deployed in most of PG&E's service territory. To collect system load data, PG&E uses SCADA metering that monitor certain assets on the power grid and gather load and power quality data. SCADA meters provide real-time operational data so that PG&E can more effectively improve power profiling and operate the grid. This data is fed into LoadSEER to help inform more accurate load forecasting based on hourly profiles versus single point peaks. This data helps drive much of the understanding of how varying DER import/export profiles can be integrated into the grid.

G. EPIC 2.23 Tool Integration

The scope of the EPIC project is for LoadSEER to utilize the database and scripting platform for which the CYMDIST program is built on along with new efficient server side capabilities. Since these tools are used by PG&E distribution planning for both forecasting and interconnection the idea is to be able to directly have these new capabilities with ICA to more directly and efficiently inform the Distribution Planning Process.

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[23] http://www.integralanalytics.com/products-and-services/spatial-growth-planning/loadseer.aspx.

(D) Schedule/Gantt Chart

Task	Date Due
Initiate ICA Working Group	12 May 2016
File Revised Demo A Plan	16 June 2016
Meet monthly to monitor and support Demo A	Q2 – Q4 2016
Execute Tasks on Selected Areas	Q3 2016
Status Report to Working Group on Demo A	Q3 2016
Finalize Results and Comparative Analysis	Q4 2016
Final Report on Demo A	Q4 2016

The timeline may change depending on ICA Working Group coordination, requests, and recommendations. Below is a detailed Gantt chart relating specific Demonstration A objectives to the proposed timeline for Demonstration A.

The figure below is a Gantt chart depicting the expected timeline of the various objectives that are planned to drive Demo A.

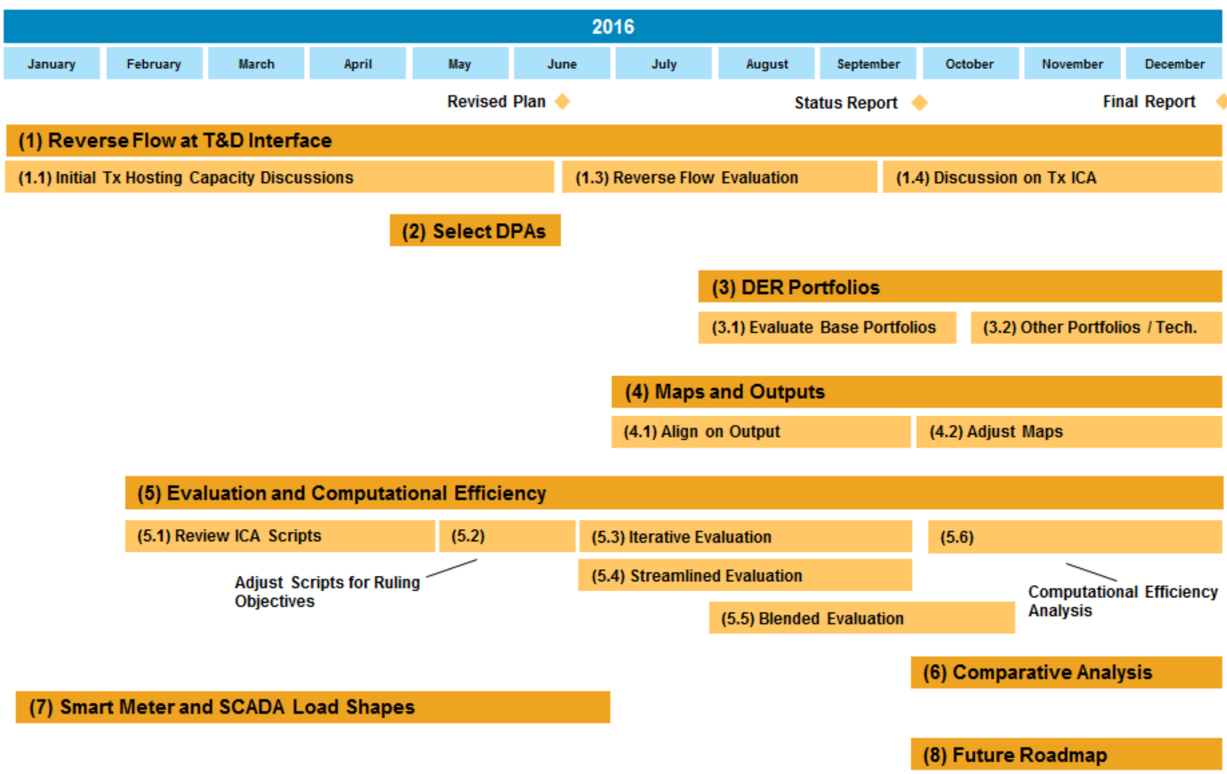

Figure 11 - Demo A Gantt Chart

(E) Additional Resources

At this time PG&E is utilizing internal resources and crossover work/resources in the EPIC 2.23 project. No additional resources are expected to be needed at this time. As part of this demonstration project, PG&E is evaluating feasibility of calculation techniques and computational efficiency. Additional resources may be needed depending on the outcome of the demonstration project, specific recommendations by the working group, and/or commission decision on final ICA methodology. If determined to be necessary, PG&E will inform the Working Group and Commission on the resource needs in the final report for Demonstration A.

(F) Monitoring and Reporting Progress and Results

The demonstration project will provide reporting of progress and results to the ICA Working Group as directed until the completion of the project. The demonstration project will provide at a minimum the following reports:

1.) Revised Plan – June 16, 2016
2.) Intermediate Status Report – Q3 2016
3.) Final Report – Q4 2016

PG&E will attend the Working Group monthly meetings to report the progress of Demonstration Project A. Over the course of the project, PG&E will submit an intermediate report, in the third quarter of 2016, to the Working Group for the project progress and a final project report, in the fourth quarter of 2016, to the CPUC Energy Division, who may provide further guidance on the content and format of the report.

(G) Availability of Project Files

The detailed ICA results will be made publicly available using PG&E's online maps as well as in a downloadable format. In addition, PG&E will make the electronic files of the Demonstration Project A available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files.

(H) Comparative Evaluation and Benchmarking

All ICA results from both methods will be compared on a node-by-node basis, and the comparisons will be conducted by limitation category, by DER scenario, by location, by frequency and by duration. Essential statistics will be extracted from the full scale comparison to provide an indication of the consistency of the results from both methods.

The computing resources needed for both methods in Demonstration Project A are recorded, by which the computing resources required for a system wide ICA can be estimated. This information can provide information to help evaluate methods that may improve the computational efficiency of the ICA tools and process in order to calculate and update ICA values across all circuits more frequently and accurately.

With all the knowledge obtained during the comparative assessment, both internally or externally, PG&E will investigate the root causes of the differences observed in two methods and to identify possible improvements to the results of each method, aiming to identify a best method for an efficient and effective system wide Integration Capacity Analysis.

The details of the comparative assessment methodologies, results evaluation, identified improvement and the best ICA method identified will be reported in the intermediate report and reviewed by ICA Working Group before submitting to the Commission.

The following section outlines how the demonstration project will establish comparison and the need for further qualification and testing for wider use across the service territory. Comparative evaluation will be performed as requested by the ACR.[24] The ICA Working Group recommendations for comparative evaluation are as follows with brief descriptions of how PG&E plans to meet them:

1. **A detailed comparative summary of the methodologies and the content and format of results from the ICA analyses to be performed through Demo A projects.**
    - IOU and ICA Working Group coordination will be performed to ensure effective reporting of comparative results at the monthly meetings
    - PG&E will evaluate and compare both iterative and streamlined approaches
    - PG&E will evaluate and compare results from a set of representative circuits that all three IOUs will analyze with the methodology

2. **A detailed common comparative evaluation explaining how results of the individual IOU Demo A projects will be analyzed to allow comparison of: a) ICA accuracy; b) ICA consistency; c) incremental ICA computing needs and costs; d) ICA computing time; e) ability to model both different types of DERs and DER portfolios, as well as different scenarios system wide.**
    - PG&E will utilize direct comparison of values and standard error/difference evaluation to (a) determine accuracy of streamlined compared to detailed/iterative, (b) consistency between IOUs, (c) computing time differences between iterative and streamlined
    - For (d), as discussions develop on need to analyze new DER portfolios and technology, this comparison is two-fold. First, it will be evaluated if the technique has the ability to consider the new requirement which will be a binary assessment. Second, it will be evaluated on the additional computation needed to consider the new requirement and use quantifiable processing times to understand additional needs.

3. **Recommended protocol for baseline tests using reference circuits, for discussion and approval by the ICA working group. The baseline testing should test the full range of circuits, projected loads, and DER penetration across IOUs, and will test each**

[24] May 2nd Ruling Appendix, pp. 19 list item '3.1.e'.

individual ICA criteria (e.g., thermal, protection, power quality, safety). Testing on a single sample circuit will not be sufficient to demonstrate compliance with the CPUC requirement for consistency.

- Compare results on a node-by-node basis,
- Compare results on a category-by-category basis
- Evaluate representative circuits across all three IOUs. The ICAWG agreed that a single IEEE circuit will not be sufficient. PG&E is willing to explore using the circuits in the demo and anonymizing them or EPRI California Solar Initiative circuits that were representative of the three IOUs. The specific circuits used can be discussed in more detail with the ICAWG.
- These circuits will be anonymized to ensure review and availability of project files to the ICA Working Group

4. **Discussion of how working group input regarding optimal granularity and frequency of updates will be incorporated in the Demo A projects.**
   - Review and discuss with ICA Working Group at monthly meetings on updates as analysis and data is gathered

5. **A process for publishing the details of the methodologies, testing their consistency, and results should include reviews by the ICA WG prior to being submitted to the CPUC.**
   - Review and discuss results as available with Working Group to feed into the required ICA Working Group reports
   - Frequency and format can be discussed and evaluated as results and data are retrieved from the project

6. **A process for not only testing the speed and accuracy of both methods, but also identifying improvements to the results of each method.**
   - Reports, review, and discussion with the ICA Working Group will be utilized to identify possible improvements and inclusion of recommendations as required by the ACR
   - At a minimum the monthly meetings can be used to gather and provide input upon IOU discussion of progress and results

7. **Use outside resources (e.g. EPRI work) as a starting point for developing and evaluating each method, where possible.**
   - EPRI will be utilized as a starting point for evaluation with their work internally with the Integrated Grid Framework working with hosting capacity as well as California Solar Initiative projects performing various studies on DER integration

The three IOUs will collaborate on using similar circuits from the EPRI California Solar Initiative (CSI) projects on DER grid integration. One project in particular has very similar components and learnings. This project is the "Screening Distribution Feeders: Alternatives to the 15% Rule”.[25] The feeders in this project were selected as representative across the three CA IOUs. The feeders can be explored to be anonymized and shared for use across the IOUs and potentially to those ICA Working Group members looking to help provide comparative insight and new techniques.

H. Calculation Technique Comparison

The intention of the comparison between the two calculation techniques is to understand the effectiveness, accuracy, and efficiency of both approaches. Comparison approaches can be used similar to the work EPRI did in both their internal Streamlined Hosting Capacity Report[26] and their CSI studies on DER Integration[27].

The following figure is an example from EPRI’s work that may be used as a starting point for comparison, but may be adjusted as projects progress and input is gathered from ICA Working Group.

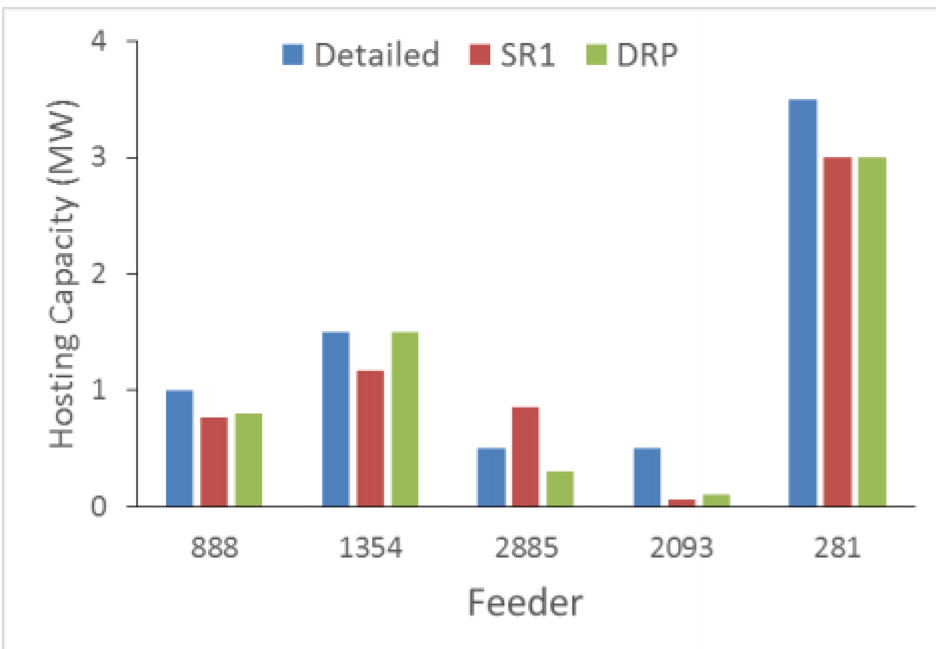

Figure 6-2.
Improving Overvoltage Hosting Capacity Prediction with Distribution Resource Plan

Figure 12 - Figure from Final Report on CSI4 Work on Alternatives to the 15% Rule[28]

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[25] http://calsolarresearch.ca.gov/funded-projects/88-screening-distribution-feeders-alternatives-to-the-15-rule
[26] *A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources: A Streamlined Approach for Solar Photovoltaics.* EPRI, Palo Alto, CA: 2014. 3002003278
[27] http://calsolarresearch.ca.gov/funded-projects/88-screening-distribution-feeders-alternatives-to-the-15-rule
[28] Page 6-2, http://calsolarresearch.ca.gov/images/stories/documents/Sol3_funded_proj_docs/EPRI/CSI-

I. IOU Benchmarking

The intention of this comparison is to determine the consistency of the implementation of methodologies across all three IOUs. Circuits used in the CSI work will be utilized and analyzed across all three IOUs. Accuracy and error will be analyzed to determine where any discrepancies reside and to focus more effort for consistency. As with the technique comparison, EPRI's metrics can be utilized to

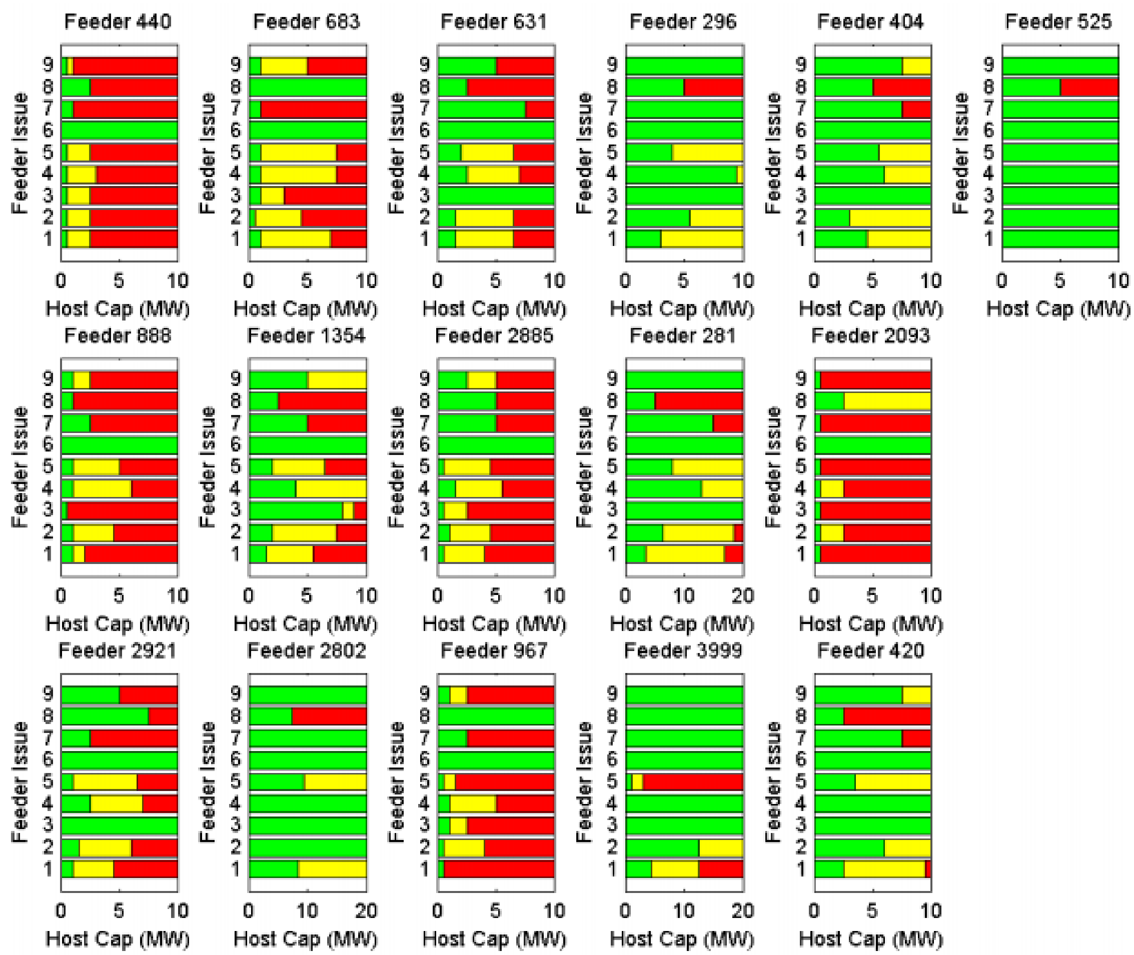

Figure 4-5.
Issue Specific Utility-Scale PV Hosting Capacity

Figure 13 - Hosting Capacity Comparison Example from CSI Project[29]

RDD_S3_EPRI_Final-Report_Dec2015.pdf.

[29] Page 4-7, http://calsolarresearch.ca.gov/images/stories/documents/Sol3_funded_proj_docs/EPRI/CSI-RDD_S3_EPRI_Final-Report_Dec2015.pdf.

(I) Success Metrics for ICA Evaluation

ORA recommended 12 success metrics in the November 10^{th} 2015 ICA workshop. These metrics are:

1. Accurate and meaningful results
   a. Meaningful scenarios
   b. Reasonable technology assumptions
   c. Accurate inputs (i.e. load and DER profiles)
   d. Reasonable tests (i.e. voltage flicker)
   e. Reasonable test criteria (i.e. 3% flicker allowed)
   f. Tests and analysis performed consistently using proven tools, or vetted methodology
   g. Meaningful result metrics provided in useful formats
2. Transparent methodology
3. Uniform process that is consistently applied
4. Complete coverage of service territory
5. Useful formats for results
6. Consistent with industry, state, and federal standards
7. Accommodates portfolios of DER on one feeder
8. Reasonable resolution (a) spatial, (b) temporal
9. Easy to update based on improved and approved changes in methodology
10. Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)
11. Consistent methodologies across large IOUs
12. Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed

The following is a listing of how the demonstration project intends to meet these success metrics.

1. Accurate and meaningful results
- Evaluating accuracy with expanded dual approach and comparison
- Increasing accuracy with granular circuit and AMI data
- Gaining ICAWG input for use cases, scenarios, and portfolios for useful results

2. Transparent methodology
- Discussion and transparency through ICAWG and demo reports

3. Uniform process that is consistently applied
- Applying automated scripting techniques to limit manual engineering error

4. Complete coverage of service territory
- Utilizing CYME gateway to create models of all circuits in our GIS system
- Computational efficiency techniques of streamlined approaches, CYME server capabilities, and cloud computing to help expand reach of analysis

5. **Useful formats for results**
    - Map and Output coordination with ICAWG for consistent and useful results to public

6. **Consistent with industry, state, and federal standards**
    - Aligning with practices and components in California Electric Rule 21, FERC Wholesale Distribution Tariff, PG&E interconnection standards

7. **Accommodates portfolios of DER on one feeder**
    - Already shown that PG&E can evaluate various portfolios and types of DER
    - Discussing expanded portfolio and technology analysis with ICA Working Group

8. **Reasonable resolution (a) spatial, (b) temporal**
    - Using granular geospatial circuit models and hourly load profiles to inform analysis
    - Granular spatiality down to primary side of service transformers that feed customer premises
    - Temporal granularity of 24 hours a day for every month of the year across varying load level probabilities (i.e. peak and minimum loading possibilities)

9. **Easy to update based on improved and approved changes in methodology**
    - Utilizing open scripting platforms within CYMDIST that require less dependence on specific tool module updates from CYME

10. **Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)**
    - Integration of LoadSEER with CYMEDIST allows direct connection to load and DER forecasts and profiles that can feed into CYMDIST for the power flow and ICA analysis

11. **Consistent methodologies across large IOUs**
    - Performing comparative assessment to ensure consistency
    - Coordinating with software vendors CYME and Integral Analytics for inclusion into tools to help drive consistency with the commercial software

12. **Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed**
    - Analysis being designed for batch analysis across the entire modeled system database in central data repositories

References

The following is a listing of external references used in the footnotes.

May 2nd Ruling on Integration Capacity Analysis Demo A

- http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF

Distribution Resource Plan Working Groups

- http://drpwg.org/

CYMDIST by CYME International

- http://www.cyme.com/software/cymdist/

LoadSEER by Integra Analytics

- http://www.integralanalytics.com/products-and-services/spatial-growth-planning/loadseer.aspx

California Solar Initiative (CSI) Research, Development, Demonstration and Deployment Program

- Screening Distribution Feeders: Alternatives to the 15% Rule
    - http://calsolarresearch.ca.gov/funded-projects/88-screening-distribution-feeders-alternatives-to-the-15-rule
- Analysis to Inform California Grid Integration Rules for PV
    - http://calsolarresearch.ca.gov/funded-projects/110-analysis-to-inform-california-grid-integration-rules-for-pv

A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources: A Streamlined Approach for Solar Photovoltaics. EPRI, Palo Alto, CA: 2014. 3002003278

http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002003278

ATTACHMENT B

PG&E Implementation Plan for Demonstration Project B

PG&E Distribution Resource Plan Demonstration Project B:

Locational Net Benefit Analysis

June 16, 2016 Implementation Plan

Demo B Table of Contents:

I. Overview

PG&E submits this detailed Implementation Plan for its DRP Locational Net Benefit Analysis (LNBA) Demonstration Project B (Demo B). The Implementation Plan describes the project execution, including metrics, schedule and reporting interval for Demo B.

Sections II and III describe the background of and commission requirements for Demo B, respectively.

Section IV describes the process by which Demo B will be executed, including the following major phases and steps:

1. Phase 1: Planning Area Selection
2. Phase 2: Identify and Describe Distribution Upgrade Projects in Selected Planning Area
    a. Step 1: Determine a list of upgrade projects
    b. Step 2: Cost estimate for existing approaches
    c. Step 3: Project Specifications
    d. Step 4: Location Specific Services
    e. Step 5: DER Capability Analysis
3. Phase 3: Calculation of Locational Net Benefits
4. Phase 4: Visualization of Information

Section V proposes a plan for engaging the LNBA Working Group in Demo B, including a suggested list of Demo B progress reports and discussion topics for monthly working group meetings.

Appendix A provides a description of PG&E's distribution planning load forecasting methodology.

Appendix B provides a preliminary description of the LNBA Calculation methodology developed by a consultant engaged for this project.

Appendix C provides general information about PG&E's proposed planning areas for Demo B: Chowchilla and Chico Distribution Planning Areas (DPAs).

Sections II – V and Appendix B of this Implementation Plan were developed in close coordination with the Southern California Edison Co. (SCE) and San Diego Gas & Electric Co. (SDG&E) – the Joint IOUs. These sections are intended to be substantially similar, though not identical, across the Joint IOUs.

The Joint IOUs elected to take this approach since much of the Implementation Plan content was prescribed by the Commission. Furthermore, the Joint IOUs have determined, through engagement with the Commission-convened LNBA Working Group, that diversity across specific planning areas chosen in the IOUs'

Demo B projects is desired but diversity of procedures and methodologies is not. The Joint IOUs have also elected to engage a common consultant to assist with Demo B.

II. Demo B Introduction and Objectives

While it includes no mention of this demonstration project, the genesis of the locational net benefit analysis is Assembly Bill 327 (2013), which added section 769(b) to the California Public Utilities Code, requiring each California investor-owned utility (IOU) to submit a distribution resources plan proposal "to identify optimal locations for the deployment of distributed resources…" using an evaluation of "locational benefits and costs of distributed resources located on the distribution system" based on savings distributed energy resources (DERs) provide to the electric grid or costs to ratepayers.

On August 14, 2014, the California's Public Utility Commission ("Commission" or CPUC) issued Rulemaking (R.) 14-08-013 which established guidelines, rules, and procedures to direct California IOUs to develop their Distribution Resources Plan ("DRP"). In a February 6, 2015 Assigned Commissioner Ruling (ACR), the Commission released guidance[1] for the IOUs in filing their DRP, including requirements for an "optimal location benefit analysis" and demonstration projects, including Demo B.[2]

The locational net benefits methodology/analysis (LNBA) will help specify the benefit that DERs can provide in a given location, particularly benefits associated with meeting a specific distribution need. Following the filing of the three IOUs' DRPs and workshops on LNBA, an ACR filed May 2, 2016 provided additional guidance to the three IOUs on further development of the LNBA in its application to Demo B, a pilot to apply the LNBA.[3]

The objectives of Demo B include:

- Satisfy commission requirements for LNBA and identification of optimal locations
- Demonstrate locational variability of DERs' T&D net benefits within the DPA(s) in contrast to current system-level approaches
- Develop DER requirements to provide those T&D benefits

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[1] "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," February 6, 2015.

[2] "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," February 6, 2015, Attachment A, pg. 4-6.

[3] "Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B," May 2, 2016.

- Provide a transparent test of LNBA methods and compile lessons learned for future work

This Implementation Plan provides a more detailed description of how the IOUs intend to fulfill the Commission's requirements for Demo B and achieve the objectives above.

III. Summary of Demo B Requirements

Area selection and upgrade projects:

The May, 2016 ACR refined the Integration Capacity Analysis (ICA) and LNBA methodology requirements for the demonstration projects. The ACR affirmed the requirement of the February, 2015 final DRP guidance to evaluate two traditional utility projects, one near term (0- 3 year lead time) and one longer term (3 or more year lead time) project.

The ACR also expanded the scope to require at least one distribution voltage support/power quality- or reliability/resiliency in addition to at least one traditional distribution capacity related deferral opportunity. Selecting two or more DPAs was required if both types of projects (capacity and voltage/reliability) were not located in the same DPA.

Methodology:

The Commission guidance on calculating LNBs provides detailed requirements for the T&D components and refers to the DER avoided cost model (DERAC) values for other system-level components, such as generation capacity and energy.

The detailed guidance on T&D requires the IOUs to identify and provide detailed information on all upgrade projects and associated services within the selected DPA(s). Where DERs can provide those services, a deferral value will be calculated using the Real Economic Carrying Charge (RECC) method. These steps are required to be performed using two different DER growth scenarios.

At this time, the LNBA does not include DER costs or DER integration/interconnection costs.

Demo B Final Deliverables

The final deliverables of Demo B will include:

1. Demo B Final Report
    1. Description of all projects identified in the selected DPA(s) under two DER growth scenarios,

    2. DER specifications and requirements for deferrable upgrades or expenses calculated using public inputs
    3. Locational net benefits results for all locations in the selected DPA(s)
    4. Locational net benefits final methodology
    5. Lessons learned and recommendations for refining and expanding LNBA
2. Commission-required outputs in machine-readable and map-based format layered over the online ICA map
    1. LNBA results heatmap
    2. DER growth heatmap
    3. Descriptions for all projects and associated services and DER requirements in selected DPA(s)

IV. Description of Demo B Process

Summary of Demo B Process

The activities that the IOUs will undertake in Demo B are categorized into four phases:

1. Planning Area Selection
2. Identify and Describe Distribution Upgrade Projects in Selected Planning Area
3. Calculation of Locational Net Benefits
4. Visualization of Information

Phase 1: Planning Area Selection

The IOUs have identified and presented to the LNBA Working Group (WG), proposed DPAs for Demo B. In addition to the Commission requirements summarized above, the IOUs have proposed DPAs for Demo B that will also be the focus of Demo A – the Integration Capacity Analysis demonstration project. The IOUs' proposed DPAs represent a broad cross section of types of customers, weather, geography and level of development.

The IOUs propose that the DPA selections be finalized at the LNBA WG meeting subsequent to the filing of this Implementation Plan. Previously provided DPA information is included here in **Appendix C**.

Phase 2: Identify and Describe Distribution Upgrade Projects in Selected Planning Area

This section outlines the LNBA specific analysis method in terms of identifying full range of applicable electric services and quantifying DER capabilities to provide such services in place of upgrade projects.

A five-step approach is suggested for this work as shown in Figure 1, which addresses the entire process of project selection, project cost estimation, service qualification and cost calculations for the qualified services. These steps will be undertaken for the two required DER growth scenarios.

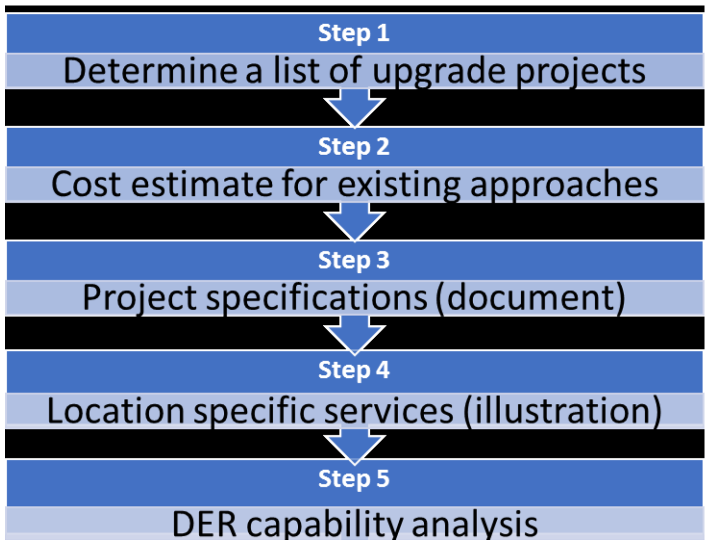


Figure 1 - Project identification and service qualifications

Each IOU has an iterative distribution planning process which identifies needed work using information about installed equipment, its performance and forecasts of future conditions that this installed equipment could experience. Recognizing the importance of this forecast of future conditions, the May, 2016 ACR requested each IOU include a description of its load forecasting methodology in this implementation plan. This description is included as **Appendix A**.

Per the May 2016 ACR, the IOUs will modify their standard planning forecast to incorporate DER growth scenarios 1 and 3 from the July 1, 2015 DRPs, respectively these scenarios represent the IEPR trajectory case and the very high DER growth scenario. The base case will use scenario 1 and a sensitivity analysis will re-evaluate steps 1-5 with the very high DER growth scenario.

Step 1: Determine a List of Upgrade Projects:[4]

Given the future work identified in each IOU's distribution planning process under these modified forecasts, the first step of Demo B is to identify the full range of upgrade projects and associated electric services in the Demo B DPA(s). The

[4] See section 4.4.1(A) and (B) and 5.1 of the May 2016 ACR.

service coverage will account for all locations within DPAs selected for the analysis. The list will include any and all electrical services that can be identified through investigation of processes involving determination and planning for distribution grid upgrade projects in three categories of:

- Utility distribution planning processes
- Circuit reliability/resiliency improvement processes
- Maintenance processes

To assess the value of a service through DER, first, a comprehensive list of locations and project types will be prepared in three project areas of: 1) capital upgrade projects, 2) circuit reliability enhancement projects, and 3) maintenance projects. The timeframe of interest to identify projects covers four horizons:

- Near term forecast (1.5-3 years),
- Intermediate term (3-5 years),
- Long term (5-10 years), and
- Ultra-long-term forecast that extends beyond 10-year horizon if supported in existing tools

For each selected DPA, the IOUs will consult with their respective departments responsible for distribution planning, reliability, district planning, and electric distribution operations, and maintenance to identify upgrade projects for the DPAs selected. Project types will include thermal capacity upgrades (e.g. feeder reconductors or additions, new transformer banks), voltage-related upgrades (e.g. voltage regulators, capacitors, VAR compensators), instrumentation and controls (e.g. SCADA and distribution automation upgrade projects, automation of voltage regulation equipment, voltage instrumentation), reliability upgrades (e.g. cable and equipment replacement projects, switch additions, customer/feeder reduction projects), and maintenance projects (e.g. pole testing and tagging).

Each upgrade project will be described in detail, including a description of the underlying need, equipment lists and project specifications. Each project will be described in terms of the associated services, such as voltage control/regulation. In characterizing each service, the following key definitions and questions will be addressed:

- A detailed description of the service
- How is the service provided today?
- What are the requirements for the service?
- How does location impact the service?
- How would DER provide this service?
- What is the value of the service today?
- What changes to existing processes would be required for DER to provide this service, if applicable?

By virtue of investigating services associated with specific upgrades in the selected DPAs, only electric services that could result in “avoided costs” will be included. One exception is conservation voltage reduction (CVR), which is effectively an energy efficiency service that DERs may be able to provide if controlled and operated by the utility but which is not typically associated with distribution upgrade projects.

Any DER-related installation and operation aspects that are necessary for interconnecting to the utility grid and operating in conjunction with the grid to produce power will not be considered as DER services.

The IOUs will develop a preliminary list of electric services that are currently being provided to customers or potentially can be offered to customers. In addition, a review of industry reports will be performed to expand the list. The literature search will include resources such as CPUC and other PUCs applicable regulation, California Independent System Operator (CAISO) and other ISO planning and operations procedures, and industry publications, and specialized literature on related topics (e.g., value of solar, etc.). The IOUs will identify key features of these services, assess how DER may benefit/impact them, and outline how the latter could be evaluated.

In addition to reviewing internal processes to determine services, the IOUs will leverage industry experience in this area based on the work done by utilities in other states where high penetration levels of PV systems exist, such as Hawaiian Electric, PEPCO Holdings Inc., Duke Energy, Eversource, etc. to gather data on service classifications and value proposition for DERs.

Step 2: Cost Estimate for Existing Approaches[5]:

For each project identified and documented in Step 1, the existing planning-level cost estimation approaches will be utilized to determine planning/budgetary cost estimates for the project.
For instance, the planning-stage cost of a cable replacement project will be calculated based on costs associated with several items, such as:

- Development costs, including siting, permitting and insurance
- Engineering and design costs
- Equipment selection and material procurement costs
- Construction and installation costs
- Inspection, commissioning and energizing costs
- Project management and site supervision costs

The above cost items may be estimated on a unit cost or percentage basis. For instance, material costs may be calculated based on the cable price per miles; however, project management may be calculated as a percentage of the total construction and engineering costs (e.g. 5 to 10% of the lump sum value).

[5] See section 4.4.1(A) and (B) of the May 2016 ACR.

The IOUs will use public cost information wherever possible so that this information can be shared among the IOUs and other stakeholders. Any confidential cost information will not be shared publicly or among the IOUs.

Step 3: Project Specifications:
As part of this step, a specification sheet will be prepared for each planned project identified in Step 1. The specification sheet will include:

- Project Definition: a description of various needs underlying the identified grid upgrade project. Projects are categorized as
  - Sub-transmission, substation and distribution capacity capital and operating expenditures
  - Distribution voltage and power quality capital and operating expenditures
  - Distribution reliability and resiliency capital and operating expenditures
- Project Characterization: determination of electrical parameters for each grid upgrade project, including:
  - Total capacity increase (firm capacity and timing of need),
  - Real and reactive power management schemes,
  - Power quality requirements, and
  - Reliability and resiliency targets;
- Project equipment list: a list of all components and tools required to complete the project, including the specific equipment listed in section 5.5.1 as appropriate:
  - Voltage Regulators
  - Load Tap Changers
  - Capacitors
  - VAR Compensators
  - Synchronous Condensers
  - Automation of Voltage Regulation Equipment
  - Voltage Instrumentation
- Project services and specifications: specifications on how a project will provide the specific services required, including the specific services listed in section 4.4.1:
  - Voltage control or regulation services
  - Reactive supply services
  - Frequency regulation services
  - Power quality services (e.g. mitigation of harmonics, spike, flickers, etc.)
  - Energy loss reduction services
  - Equipment life extensions
  - Improved SAIFI, SAIDI, and MAIFI
  - Conservation voltage reduction

- Volt/VAR optimization

Step 4: Location Specific Services:
In this step, a spreadsheet will be prepared to provide location-specific list of applicable electric services as part of each planned distribution upgrade project, for example by feeder or line section. The spreadsheet will be used to develop an illustrative map of the size, types and distribution of the services by the project locations.

Step 5: DER Capability Analysis:[6]
In this step, DER requirements to provide distribution services will be determined. A DER capability analysis will be performed to determine whether a DER can provide the services and if yes, what DER technologies and features will be required to meet the service classifications. The analysis will determine DER characteristics and requirements to provide various electrical services identified and described in Step 3 for each upgrade project and the locational requirements identified in Step 4.
The IOUs will consider all applicable DER technologies including, per section 4.4.1(B):

- Synchronous generator based DERs, such as gas engines, hydro power plants, bio-mass units and combined heat and power (CHP) plants, or any other similar technologies.
- Power electronic based DERs utilizing "standard" (conventional) inverters/converters (with limited power factor or control capabilities), such as presently deployed UL-certified PV inverters, and,
- Power electronic based DERs utilizing "smart" (advanced) inverters/converters functionalities, such as bidirectional and four-quadrant battery energy storage systems, and advanced PV inverters.

A high-level qualification table, as an example, is shown below.

Table 1 – Qualification of DER capability in providing a special service

Services	CHP	Standard Inverters				Smart Inverters			
		PV	Fuel Cell	Wind Type 4	Energy Storage	PV	Fuel Cell	Wind Type 4	Energy Storage
Voltage control/regulation	High (certain types)	None	None	None	Medium (kVA limit)	Medium (Production Priority)	Medium (Production Priority)	Medium (Production Priority)	High (certain types)
Reactive supply	High (certain types)	Low (limited pf range)	Low (limited pf range)	Low (limited pf range)	Medium (kVA limit)	Medium (Production Priority)	Medium (Production Priority)	Medium (Production Priority)	High (certain types)
Frequency regulation	Low (slow response time)	None	None	None	High (certain types)	Low (uni-directional)	Low (uni-directional)	Low (uni-directional)	High (certain types)

In addition to the DER capabilities to provide the service, the IOUs will investigate and describe any changes that need to be applied into existing

[6] See section 4.4.1(C) of the May 2016 ACR.

processes to support certain services through DERs.

Phase 3: Calculation of Locational Net Benefits

A total avoided cost will be calculated for each location in the selected DPA(s). Per table 2 of the May, 2016 ACR, this will include

1. Avoided T&D
2. Avoided Generation Capacity
3. Avoided Energy
4. Avoided GHG
5. Avoided RPS
6. Avoided Ancillary Services
7. Renewable Integration Costs, Societal Avoided Costs and Public Safety Avoided Costs

Components 2-6 above will be borrowed from the DERAC model with the exception that a flexibility factor will be added to incorporate avoided flexible capacity into Component 2. Component 7 will be described qualitatively with the exception that the default renewable integration costs from the Renewable Portfolio Standard (RPS) Proceeding will be incorporated.
The avoided T&D cost will be calculated using the Real Economic Carrying Charge method to calculate the deferral value for each project. These will be assigned to one of the four subcategories below:

1. Sub-transmission, substation and distribution capacity capital and operating expenditures
2. Distribution voltage and power quality capital and operating expenditures
3. Distribution reliability and resiliency capital and operating expenditures
4. Transmission capital and operating expenditures

The Joint IOUs have engaged Energy and Environmental Economics (E3), the original developer of the DERAC tool, to develop detailed LNB methodologies and a tool implementing those methodologies. A preliminary description of the detailed methodologies is provided in **Appendix B.**
This tool will be made public as will inputs and other data to the extent this information is not confidential. As indicated previously, the IOUs will use public inputs and data wherever possible.

Phase 4: Visualization of Information

As part of this task, the LNBA Demo B maps will be created that can be overlaid on the Integration Capacity Analysis results. Per section 4.4.2 of the May, 2016 ACR, three separate maps will be created:

1. Locations of upgrade project areas with details, associated services and, where appropriate, location-specific DER specifications
2. DER growth heat maps

3. LNBA results heat map showing the total avoided cost across selected DPAs based on public information

The maps will include opportunities for conservation voltage reduction (CVR) and volt/VAR optimization services, and any additional services that are deemed feasible in the analysis.

V. Detailed Schedule and Stakeholder Engagement

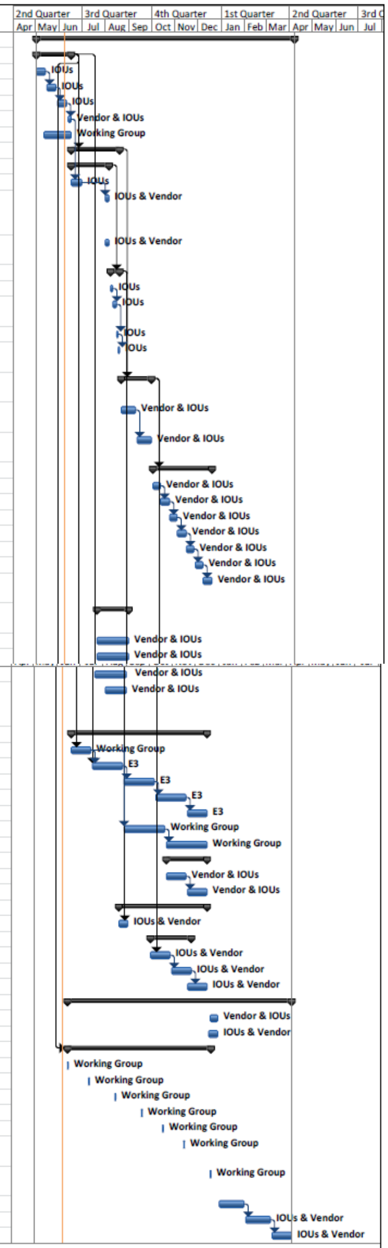
List of Tasks and Schedule

The Gantt chart below captures the proposed implementation plan for the locational net benefits methodology/analysis to be conducted by the IOUs. The schedule consists of six primary tasks. The first and last tasks address the initial planning, and the monitoring and reporting of progress, respectively. The remaining tasks contain the detailed activities required to execute the four phases of the project described in detail elsewhere in this document, namely Phase 1 - Planning Area Selection, Phase 2 - Identify and Describe Distribution Upgrade Projects in Selected Planning Area, Phase 3 - Calculation of Locational Net Benefits and Phase 4 - Visualization of Information.

To ensure progress is monitored, the schedule makes provisions for monthly working group meetings. These meetings will have two goals; the first is to review activities and track progress, the second is to focus on key technical aspects relevant to activities at that juncture in the project. The Gantt chart identifies the technical focus area for each meeting.

Some of the activities have to be executed sequentially and the Gantt chart documents these dependencies. Some of the activities are time-bound and must be completed by a certain date, and the Gantt chart back-calculates the sequencing of activities to ensure the deadlines are met. The Resource Names column identifies which of the team members is responsible for executing that specific activity. When more than one name is listed, the first team member listed has lead and any subsequent team member(s) have supporting roles.

ID		Task Mode	Task Name	Duration	Start	Finish	Predecessors	Resource Names
1			**LNBA Implementation Plan**	**245 days**	**Mon 5/2/16**	**Fri 4/7/17**		
2			**Complete and File Implementation Plan**	**34 days**	**Mon 5/2/16**	**Thu 6/16/16**		
3			Methodology description	10 days	Mon 5/2/16	Fri 5/13/16		IOUs
4			Load forecasting description	10 days	Mon 5/16/16	Fri 5/27/16	3	IOUs
5			Initial considerations for DPA selection and Demo projects	10 days	Mon 5/30/16	Fri 6/10/16	4	IOUs
6			Prepare schedule and Gantt chart	4 days	Mon 6/13/16	Thu 6/16/16	5	Vendor & IOUs
7			Working group participation and reporting	26 days	Thu 5/12/16	Thu 6/16/16		Working Group
8			**Review and finalize Demo B projects (LNBA)**	**46 days**	**Fri 6/17/16**	**Fri 8/19/16**	**2**	
9			**Characterization and selection of DPAs**	**36 days**	**Fri 6/17/16**	**Fri 8/5/16**		IOUs
10			Perform load forecasting	10 days	Fri 6/17/16	Thu 6/30/16	6	IOUs
11			List of all upgrade projects in DPAs (cable replacement, SCADA enhancement, equipment change, etc.) - irrespective of DER scenarios	5 days	Mon 8/1/16	Fri 8/5/16	10	IOUs & Vendor
12			List of all voltage support/power quality or reliability/resiliency related projects	5 days	Mon 8/1/16	Fri 8/5/16		IOUs & Vendor
13			**Finalize selection of Demo B projects**	**10 days**	**Mon 8/8/16**	**Fri 8/19/16**	**9**	IOUs
14			Select one Capital project	3 days	Mon 8/8/16	Wed 8/10/16		IOUs
15			Select one voltage quality / reliability / maintenance related project	3 days	Thu 8/11/16	Mon 8/15/16	14	IOUs
16			Select one near term and One long-term time frame	2 days	Tue 8/16/16	Wed 8/17/16	15	IOUs
17			Select territory diversity (e.g. one urban and one rural area) projects	2 days	Thu 8/18/16	Fri 8/19/16	16	IOUs
18			**Determine additional upgrade projects based on the two DER growth scenarios**	**30 days**	**Mon 8/22/16**	**Fri 9/30/16**	**8**	
19			include projects from distribution planning process, circuit reliability improvement process, and maintenance process	15 days	Mon 8/22/16	Fri 9/9/16		Vendor & IOUs
20			identify possible elimination or incremental upgrade projects based on High DER forecast	15 days	Mon 9/12/16	Fri 9/30/16	19	Vendor & IOUs
21			**Document upgrade projects**	**56 days**	**Mon 10/3/16**	**Mon 12/19/16**	**18**	
22			Location and type of projects	8 days	Mon 10/3/16	Wed 10/12/16		Vendor & IOUs
23			Project specifications	8 days	Thu 10/13/16	Mon 10/24/16	22	Vendor & IOUs
24			Parameters of the projects	8 days	Tue 10/25/16	Thu 11/3/16	23	Vendor & IOUs
25			Need identified in upgrade project	8 days	Fri 11/4/16	Tue 11/15/16	24	Vendor & IOUs
26			Equipment necessary for upgrades	8 days	Wed 11/16/16	Fri 11/25/16	25	Vendor & IOUs
27			Estimated cost of upgrade using traditional methods	8 days	Mon 11/28/16	Wed 12/7/16	26	Vendor & IOUs
28			Determine timeframe of upgrades (short-term, near-term, and long-term)	8 days	Thu 12/8/16	Mon 12/19/16	27	Vendor & IOUs
29			**Review and finalize full range of electric services by DER for avoided costs in all locations**	**30 days**	**Thu 7/21/16**	**Wed 8/31/16**		
30			Identify need attributes that DERs could potentially defer	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
31			Identify area in which DERs must locate to mitigate need	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
32			Identify location-specific electric services associated with projects	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
33			Determine DER capabilities and specifications to offer the services Include capabilities of standard and smart inverters as well as synchronous machines	20 days	Thu 8/4/16	Wed 8/31/16		Vendor & IOUs
34			**Develop LNBA tool (E3 tool) plus additions**	**130 days**	**Mon 6/20/16**	**Fri 12/16/16**		
35			Methodology	20 days	Mon 6/20/16	Fri 7/15/16	2	Working Group
36			RECC method for avoided cost of projects	30 days	Mon 7/18/16	Fri 8/26/16	2,35	E3
37			DERAC values for energy and capacity	30 days	Mon 8/29/16	Fri 10/7/16	36	E3
38			Include flexible capacity "flexibility factor"	30 days	Mon 10/10/16	Fri 11/18/16	37	E3
39			Include renewable integration costs	20 days	Mon 11/21/16	Fri 12/16/16	38	E3
40			Determine a list of potential societal or public avoided costs	40 days	Mon 8/29/16	Fri 10/21/16	35	Working Group
41			Defining the associated project specific metrics	40 days	Mon 10/24/16	Fri 12/16/16	40	Working Group
42			**Calculate total LNB for Demo B specific locations and projects**	**40 days**	**Mon 10/24/16**	**Fri 12/16/16**		
43			Perform LNBA for Demo B Project group 1 (capacity type)	20 days	Mon 10/24/16	Fri 11/18/16		Vendor & IOUs
44			Perform LNBA for Demo B Project group 2 (non-capacity type)	20 days	Mon 11/21/16	Fri 12/16/16	43	Vendor & IOUs
45			**Create a LNBA map by locations**	**85 days**	**Mon 8/22/16**	**Fri 12/16/16**		
46			Initial mapping of upgrade projects (spreadsheet and visualization)	10 days	Mon 8/22/16	Fri 9/2/16	13	IOUs & Vendor
47			**Present services on maps and describe in writing**	**40 days**	**Mon 10/3/16**	**Fri 11/25/16**		IOUs & Vendor
48			Develop machine readable format (Spreadsheet)	20 days	Mon 10/3/16	Fri 10/28/16	18	IOUs & Vendor
49			Develop scripts and tools for transferring to maps and visualizing	20 days	Mon 10/31/16	Fri 11/25/16	48	IOUs & Vendor
50			Examine and publish overlay on the map (go live)	20 days	Mon 11/21/16	Fri 12/16/16	49	IOUs & Vendor
51			**Monitoring and Reporting**	**213 days**	**Wed 6/15/16**	**Fri 4/7/17**		
52			*Demo B Report*	*8 days*	*Wed 12/21/16*	*Fri 12/30/16*		*Vendor & IOUs*
53			*Intermediate report on long term enhancements*	*10 days*	*Mon 12/19/16*	*Fri 12/30/16*		*IOUs & Vendor*
54			**Reporting to the working group**	**136 days**	**Wed 6/15/16**	**Wed 12/21/16**	**2**	
55			June Meeting (LNBA Plans submitted to CPUC June 16th)	1 day	Wed 6/15/16	Wed 6/15/16		Working Group
56			July Meeting (Review Demo Project A and data)	1 day	Wed 7/13/16	Wed 7/13/16		Working Group
57			August Meeting (Update on Pilot Projects)	1 day	Wed 8/17/16	Wed 8/17/16		Working Group
58			September Meeting (LNB Methodology: Deep Dive)	1 day	Wed 9/21/16	Wed 9/21/16		Working Group
59			October Meeting (LNB Maps: Discussion on Output Format)	1 day	Wed 10/19/16	Wed 10/19/16		Working Group
60			November Meeting (LNB Methodology: Calculated LNBs from Pilot Projects and Development of Requirements)	1 day	Wed 11/16/16	Wed 11/16/16		Working Group
61			December Meeting (Report Submitted/ LNB Maps: Lessons Learned and Future Refinements)	1 day	Wed 12/21/16	Wed 12/21/16		Working Group
62			Stakeholder Review	25 days	Mon 1/2/17	Fri 2/3/17		
63			Enhancements	25 days	Mon 2/6/17	Fri 3/10/17	62	IOUs & Vendor
64			*Final report*	*20 days*	*Mon 3/13/17*	*Fri 4/7/17*	*63*	*IOUs & Vendor*



Project: Schedule - V1
Date: Wed 6/8/16

Task | Split | Milestone | Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | Deadline | Progress

Page 2

Stakeholder Engagement: Working Group Report out Schedule and Metrics

The schedule below provides an expected ordering of Demo B status reports to the LNBA WG in 2016. It does not include other WG activity, such as discussions on long-term refinements to LNBA.

1. June (Complete) – Working group role and review of Demo B requirements

2. June (Complete) – More detail on Implementation Plans, present selected DPAs
3. July – LNB methodology deep dive #1
   - IOUs will and possibly their consultant(s) will present for discussion the Implementation Plan process and detailed methodologies. Areas for additional clarification or development will be identified.
4. August – Review Demo B progress and data on upgrade projects
   - IOUs will present preliminary list of upgrade projects in Demo B DPAs.
5. September – Review Demo B progress and review preliminary list of electric services
   - IOUs will review their preliminary list of electric services with other IOUs and stakeholders as part of the working group activities, incorporate comments and suggestions, answer questions, and identify gaps that require more extensive research.
6. October – Mapping and output format
   - IOUs will seek input on the format of LNBA results, prioritization of LNBA map features.
7. November – LNB methodology deep dive #2
   - IOUs will present for discussion Demo B process and methodologies to date, with an emphasis on areas identified in July for additional clarification or development. If possible, a preliminary version of the E3 tool will be shared at this point.
   - IOUs will present for discussion preliminary results on upgrade deferral values and DER requirements.
8. December – Present draft Demo B Report and lessons learned
   - IOUs will present draft LNBA maps and will seek input on lessons learned from Demo B and recommendations. IOUs will compare calculated LNB results to existing system-wide estimates of T&D benefits.

In addition, the IOUs propose to report out their estimated percent completion metric on the major phases and steps identified in this document on a monthly basis.

VI. Conclusion

PG&E appreciates the opportunity to share this DRP Demo B Implementation Plan with the Commission, Energy Division staff and interested stakeholders. PG&E and the Joint IOUs have striven to provide a detailed description of the anticipated activities and timing of Demo B. PG&E will continue to coordinate closely with the IOUs and with the LNBA working group to ensure the objectives of Demo B are met and this project provides useful and actionable insights to apply in future iterations of the LNBA.

Appendix A – Load Forecasting Methodology

PG&E provided a detailed description of its distribution load forecasting methodology in the July 1, 2015 Distribution Resources Plan at pages 16-21 and Appendix B. This section primarily draws from that description.

Each year, PG&E's distribution engineers forecast the magnitude and location of load growth to ensure that adequate distribution capacity is available to meet peak demand. PG&E's distribution service territory consists of over 3,000 feeders and 1,300 distribution transformer banks assigned to roughly 250 distribution planning areas (DPAs).

PG&E uses the LoadSEER[7] distribution load growth program to prepare a 10-year growth projection for each feeder, bank and DPA. This analysis uses historical load and temperature data, geospatial economic factors and imagery, customer class information, and allocated system level forecasts – primarily an allocation to each acre of PG&E's distribution service territory of the California Energy Commission's adopted California Energy Demand base case peak load forecast for PG&E's distribution system.

A significant amount of analysis is performed to normalize historical data, convert between simultaneous and non-simultaneous peak forecasts for each circuit and adjust forecasts using local knowledge such as new known loads, firm capacity agreements or large generators.

Impacts from existing DERs are embedded in historic data, and to the extent that they are incorporated by PG&E and the CEC's adopted base case peak load forecast, LoadSEER geospatial forecasts incorporate future load impacts due to DERs.As described in its DRP, PG&E updates the load forecast annually to capture distribution system changes due to non-capacity related expenditures (i.e., modifications associated with work to connect new customers, improve reliability and operational flexibility, asset replacement, Rule 20A, etc.) and load growth, which varies over time.

Consequently, plans relating to distribution capacity change from year to year. From a detailed capacity planning perspective, PG&E typically identifies new feeder projects approximately two years in advance and new substation transformer projects approximately two-to-three years in advance.PG&E uses its load forecasting process to project DPA load growth 10 years into the future in order to develop preliminary plans and expenditure estimates for future capacity additions and to identify the need for new substation projects, which can have long lead times.

[7] Additional detail on the LoadSEER tool is provided in the PG&E's Demonstration A Implementation Plan.

Appendix B:

Locational Net Benefit Analysis Modeling for Demonstration B

Contents

1 Introduction

E3 was retained by the three investor owned utilities (IOUs) in this proceeding to build a simple model for estimating location-specific avoided costs of installing distributed energy resources (DERs) based on a specific approved LNBA methodology framework provided to the utilities by Assigned Commissioner Picker's ruling of May 2, 2016 (ACR) for Demonstration B.[8] The model is based upon the ACR's requirements and publicly available information. The IOUs requested E3 prepare this model to ensure consistency with the prescriptive directives of the ACR regarding the structure of the LNBA and to facilitate Commission evaluation of the LNBA methodology. This document describes the modeling used for calculating the locational net benefits (LNBs) for the IOUs' Demonstration B projects (Demo B Modeling), and was developed by E3. The model (LNBA tool) will be made public to allow for review of the methodology, but actual utility-specific input values are not intended to be disclosed to market participants.

The Demo B Modeling includes system level avoided costs associated with load changes from DERs, including those from the DER Avoided Cost (DERAC)[9] (avoided energy, generation capacity, losses, ancillary services and avoided RPS and GHG compliance costs), flexible resource adequacy (RA) capacity, and an integration cost adder. E3 presents a framework to calculate local avoided costs of DERs in greater detail than in previous tools. This involves replacing the T&D component used in the DERAC explicitly with more detailed and location-specific avoided cost categories indicated in the ACR:

1. Avoided sub-transmission, substation and distribution capacity capital and operating expenses
2. Avoided distribution voltage and power quality and operating expenditures
3. Avoided distribution reliability and resiliency capital and operating expenditures
4. Avoided transmission capital and operating expenditures

In addition, conservation voltage reduction (CVR) opportunities will be considered.

[8] The ACR can be found here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF.
[9] The latest DERAC tool is available here: https://ethree.com/public_projects/cpuc5.php.

E3 has investigated how each of the above potential avoided costs can be calculated for Demo B through discussions with the IOUs. The following methodological components are employed in the Demo B Modeling for each of the above avoided costs:

1. **Avoided sub-transmission, substation and distribution capacity capital and operating expenses.** These investments are needed to safely and reliably accommodate load-growth. The avoided cost for this category follows the deferral methodology presented in the document below. Operating expenses would be an annual savings during the years of deferral or an ongoing annual savings if the investment can be avoided. If the construction of the original project would reduce capital and/or operating expenses elsewhere, those cost savings would be accounted for to correctly evaluate the *net* change in capital and operating cost.

2. **Avoided distribution voltage and power quality and operating expenditures** Discussions with the IOUs indicate that the driver for some of these investments could also be load growth. The LNBA model will allow avoided cost estimation for such growth-related investments. These investments may be more localized due to, for example, voltage issues at the end of a circuit. Depending on the nature of the voltage and power quality avoided upgrade identified, the geographic scope of these projects may be different from upgrades identified in category 1. Several category 2 sub segments may exist within the affected region of a category 1 upgrade. Volt/VAr opportunities are considered in this category.

   DERs have been identified as causing potential voltage issues, particularly in the case of distributed generation photovoltaics (DGPV). Currently DER penetration has not been large enough to cause voltage issues that require utility corrective investments. Hence DERs installed prior to smart inverter rollout would not avoid any investments.

   Smart inverters are designed to mitigate the voltage issues, and it is expected that smart meter development and deployment will be sufficient to mitigate DER-caused voltage issues that may occur in the future. Since going forward Smart Inverters will be a mandatory requirement in the CAI IOU interconnection tariffs, there will be opportunities for mitigating these potential voltage issues in the interconnection process. Consequently, voltage projects driven by DER penetration are not considered in this analysis. Furthermore, improvements beyond current standards for voltage and power quality are assumed to have zero avoided cost value because there are no investments scheduled to improve voltage beyond Rule 2 value and power quality.

3. **Avoided distribution reliability and resiliency capital and operating expenditures**
   Reliability and resiliency projects are primarily driven by factors such as equipment age and condition, equipment location and system configuration, remote communication and control and disturbance events that result in outages. The provision of reliability and resiliency improvements would require the ability of the DER to improve system metrics such as SAIDI, SAIFI and MAIFI. There may be cases where unloading of the demand on existing equipment could allow for the existing equipment to continue to provide adequate service and defer equipment upgrades or replacements (e.g.: where the load reduction allows for an existing backtie to support the cutover of load during a disturbance event). The LNBA tool would use the deferral methodology to develop avoided costs for the demand reductions needed to relieve the existing equipment in those cases.

   There may also be cases where the ability to operate an area as an island (e.g.: micro-grid applications) offer the opportunity for extensive DER in combination with other enabling technologies and investments to defer or replace the need for traditional reliability improvements to the area. The LNBA Tool deferral framework could be applied in those cases by evaluating DER impacts on load in all hours rather than just the peak period.

4. **Avoided transmission capital and operating expenditures**
   The framework can be applied to any level of geographic specificity from line segment to CAISO system level. DERs can have avoided costs related to several levels. Load-growth-driven transmission avoided costs can either be calculated the same way as category 1 investment deferrals using system level data inputs, or estimates from other modeling approaches such as the NEM public tool can be used.

   This category potentially overlaps with local RA capacity. In the cases where RA capacity is an avoided cost applicable to installed DER in the region, the model will use the lower of 1) the incremental value of local RA above system RA capacity, or 2) the avoided cost of an identified transmission project that would eliminate the local RA price premium (using the deferral methodology described below for transmission and sub-transmission level investments).

Conservation voltage reduction

Benefits in this category include greater energy efficiency and potentially reduced wear and tear on equipment such as tap changers. Unlike the other distribution value streams discussed above, the benefits of CVR would not accrue from the deferral of planned utility investments, but rather from energy savings and potentially distribution expense savings. As such, CVR would not be evaluated using the deferral methodology in the LNBA Tool, but would be incorporated via an adder to the avoided cost of energy. The benefits of CVR will only be achievable if the DER is operated in a coordinated fashion by the utility to lower the voltage and avoid energy consumption. Evaluation of CVR strategies and their potential impacts remain ongoing, and the magnitude of any adder would be specific to both the area of concern and the DER technologies and enabling technologies under consideration. The determination of any adder would be conducted outside of the LNBA Tool.

The avoided costs identified in the above categories are determined in the Demo B Modeling by calculating the deferral value of the investments identified to address a need on the system, whether they are for local or system level transmission infrastructure, voltage and power quality, or reliability and resiliency.

Other LNBA Tool functionality

In addition to estimating the localized avoided cost of the distribution services listed above, the LNBA tool will assign the costs to the local peak period, allow for avoided costs to be aggregated or pancaked when a DER in an area can affect multiple projects, and calculate the avoided cost benefits of various DER options.

The LNBA tool uses hourly allocation factors to represent the relative need for capacity[10] throughout the year. Three options for determining the hourly allocation factors are discussed here.

To determine the avoided cost benefits of DER technologies, the LNBA Tool calculates the coincidence of the technology's dependable capacity contribution with the capacity need. For example, solar peaking in daytime hours will have very little dependable capacity contribution, and therefore deferral value, for an investment on a nighttime peaking feeder.

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[10] Throughout this document "capacity" refers to distribution capacity unless indicated otherwise, such as generation capacity or DER nameplate capacity.

The use of dependable capacity, rather than the simple expected capacity contribution from DERs is important as the distribution areas become smaller and the number of feasible DER become smaller and therefore less diverse. Dependable capacity is also important for areas with high levels of DER that are weather sensitive (such as PV), as weather variations could result in large variations in net loads for the area. Dependable capacity contribution is the number of MWs of peak load reduction that a DER technology can be relied upon to produce for the purposes of capital investment planning. The model will include inputs for the IOUs to define a level of risk at the distribution level that helps determine a DER's dependable capacity contribution. Techniques to determine the dependable capacity contribution are presented for different DER types.

The LNBA Tool will incorporate the system benefits from the CPUC Avoided Cost Model (ACM) that is currently being updated. The Tool will also add the value of flexible capacity (an avoided cost component that is not included in the ACM update at this time).

2 Methodology

The locational avoided cost of installing a DER is the deferral benefit of moving investments in new T&D capacity from the original installation year to a year in the future. The T&D capacity value of a DER resource is dependent on how much capacity a resource can reliably offer during peak load times, and the subsequent realizable deferrals. For example, consider energy efficiency measures that on aggregate reduce load by 1 MW during peak load hours. Assuming that 1 MW reduction can be reliably counted on during peak load hours, the contribution towards deferral will be 1 MW. However, distribution planners have to be confident that, firstly, the energy efficiency measures are providing a dependable reduction of 1 MW, and secondly that the measures meet criteria necessary to result in deferrals.

Assessing whether a DER plan meets these criteria, and defining the assessment criteria themselves, are covered in the following methodology sections:

Deferral Value. Different methods for evaluating deferral benefits, given forecasted future net loads, are described. Uncertainty around the expected deficiency that triggers investments can be incorporated as sensitivities in the model. Adequately determining the load forecast specific to the distribution system below the point of deferrable investment is important to ensure deferrals can actually be realized. Load forecasting and its treatment in deferral evaluation are discussed. Finally, this section covers the minimum deferral criteria.

1. **DER measure of coincidence with peak load.** The coincidence of the DER's reduction in load with the highest load hours is essential. The higher the coincidence, the greater the measure's contribution to peak load reductions, and the higher it's capacity value. To evaluate this coincidence, the LNBA Tool calculates a probability of capacity need for all of the distribution area peak hours. This is discussed below in section I.B. The uncertainty in load growth is incorporated through sensitivities, while the uncertainty around DER impact is incorporated through calculating a dependable output of DER.
2. **Dependable output of DER.** This is the load reduction caused by a DER measure that a resource planner can trust to actually occur, and can therefore factor into decisions on what capacity to build. The actual dependable load reduction can vary depending on the risk profile of the local

system, and the set of resources installed. This can take the form of a derate on output for measures such as energy efficiency and storage to account for outages. However, determining the dependable load reduction is particularly important for weather-dependent DERs because of the uncertainty in their output. Dependable capacity will also depend on the penetration of existing DER due to shifting coincidence with load as more DER is added. The methodology for calculating dependable capacity is explained in section I.C.

A. Deferral Value

1. INVESTMENT PLAN

The estimation of T&D project capacity costs requires the development of a T&D supply plan. T&D capacity investments should include only work and materials that could be deferred by DERs. To the extent there are non-deferrable costs identified, these will be described, quantified and ultimately excluded from the deferral benefit calculation. Examples of costs that would not be included are:

- Costs for related work that is not deferrable by DERs - Facilities that are not deferred should be excluded because adoption of DERs has no effect on them. For example, a new circuit may relieve capacity constraints, but also eliminate the cost of connecting a new subdivision to the utility grid. If a DER defers the need for a new circuit but the utility must proceed with the work of connecting a new subdivision, then the latter's costs could not be deferred, and the costs should be excluded from the deferral benefit.
- Sunk costs - Expenditures that would need to be made prior to date when the utilities could defer the project should be excluded, as those costs also cannot be deferred.

The distribution plan costs should also be adjusted for any higher costs that the utility might incur from deferring construction. An example of this type of cost is storage fees. In one local integrated resource planning (LIRP) study performed by E3, a utility had already commissioned the construction on long lead time custom underground cable. The cable could not be re-sold to any other utility, nor could the utility store the cable on its properties. The cost of storing the cable at the manufacturer or third party sites was high enough to rule out any DER opportunities for cost effective deferral of the underground project. The higher costs from deferral should be reflected through a high equipment inflation rate. For example, if the cost of the project would increase by 10% each year the project is deferred, an inflation rate of 10% should be used instead of a default CPI-based inflation rate (typically 2% or lower).

There is uncertainty in the cost of facilities until they are procured because of changes in the cost of equipment between the time the plan is developed and the actual procurement of the equipment. The Investment costs will be represented by high, medium, and low estimates.

2. DEFERRAL VALUE

The essence of the Deferral Value is the present value revenue requirement cost savings from deferring a local expansion plan for a specific period of time. The LNBA Tool is proposed to estimate deferral value in three ways discussed below.

1. **Discrete Deferral Value ($).** The present value of savings accrued by deferring a project are calculated using the Real Economic Carrying Charge (RECC). RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral. The Discrete Deferral value will require the user to specify the number of years of deferral (e.g.: 3 years). The value will be presented as:
   a. High, medium and low dollar savings ($) along with information on the peak reductions needed to attain those savings. Peak reductions would be shown as:
      i. High, medium and low peak MW reduction, with indication of peak hours (month, hour range, etc). The range of peak load reduction is driven by the load forecast and the uncertainty around it.
      ii. High, medium and low nameplate DER installs by technology to attain the reduction if each were the only technology implemented. The model includes a relationship between installed nameplate and dependable capacity.
2. **Discrete Savings per kW ($/kW).** This is the Discrete Deferral Value divided by the kW needed to attain the deferral. High medium and low savings per kW would be produced. High would mix high cost and low kW, medium would be medium cost and medium kW, and Low would be low cost and high kW. Three sets of values would be produced:
   a. High medium and low $/kW values, where the kW is the peak load reduction. This is not specific to a DER technology.

   b. High medium and low \$/kW values, where the kW is DER nameplate kW required to achieve the deferral. These values would be technology specific.
   c. Low value of zero if insufficient peak reduction were available to enable deferral.
3. **Avoided Cost (\$/kW-yr).** This is the single year discrete deferral value (calculated following the methodology above in 1.) divided by the kW needed to attain the deferral. High medium and low savings per kW-year would be produced. This is calculated similar to the Discrete Savings per kW, except that a single year deferral is used. Note that if there are multiple investments in the plan with different service lives, the RECC for each would vary. Two sets of values would be produced:
   a. High medium and low \$/kW-yr values per kW of peak load reduction. As discussed above, the range would be produced by combining the range of investment costs and the range of needed kW, and is not DER technology specific.
   b. High, medium and low \$/kW-yr values per kW of DER nameplate. These values would be technology specific. As discussed above, the range would be produced by combining the range of investment costs and the range of needed kW. The range will not reflect uncertainty in peak contributions from technologies.

3. FORMULAS AND EXAMPLE CALCULATIONS

Figure 2**Error! Reference source not found.** illustrates a situation where a network T&D investment is needed and the project cost. The project is needed to prevent the load growth (net of naturally occurring DER) from exceeding the T&D facility's load carrying capability and allows time for project deployment prior to the actual overload. In Figure 3**Error! Reference source not found.**, the utility is targeting incremental load reduction from the red line to the green line to allow the investment to be deferred by 3 years. The deferred project's cost is slightly higher due to equipment and labor inflation costs, but this would be more than offset by the financial savings from being able to defer the project.

Figure 2. Investment in distribution project due to load growth

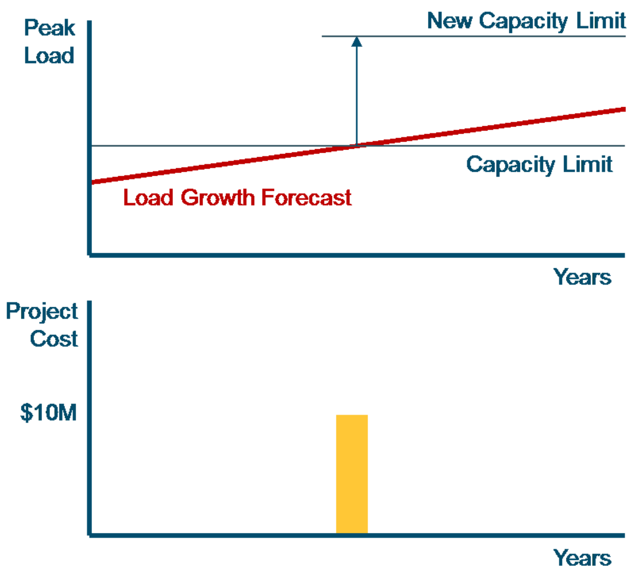
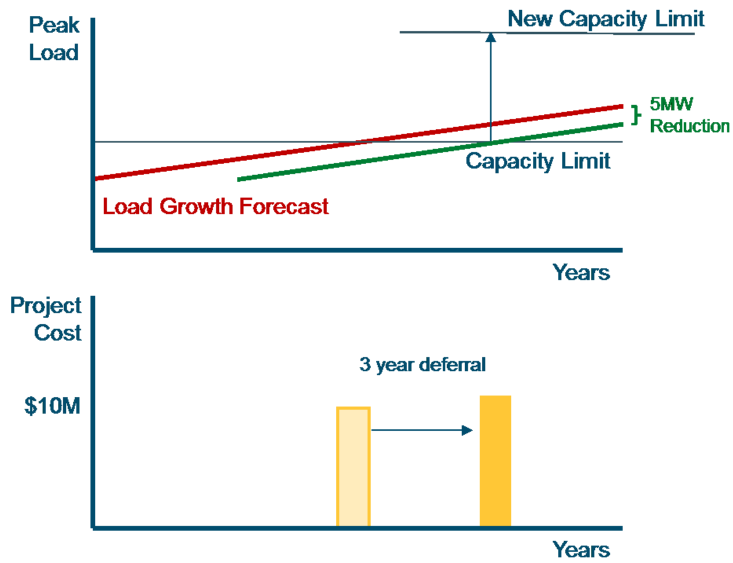


Figure 3. Project deferral of distribution investment



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Other Assumptions:

- Original Investment cost (low, med, high): $8M, $10M, $15M
- Annual incremental operating cost: $0.1M, $0.2M, $0.4M
- Asset life: 40 years
- Load reduction needed for 2 year deferral: 4MW, 6MW, 8MW
- Load reduction needed for 1 year deferral: 2MW, 3MW, 4MW
- Revenue Requirement Scaling factor: 150%
- WACC: 7.5%
- Inflation: 2%
- *RECC = 5.24%*

Note that the quantities and inputs used in this example are purely illustrative and may not resemble the inputs used in Demo B or their ranges.

Discrete Deferral Value

The savings of one year of deferral ($/yr) is:

$$SavingsOne = TDCapital[y] * RECC * RRScaler[y] + \Delta O\&M$$

The savings of multiple years of deferral is:

$$SavingsTotal = SavingsOne * \sum_{d=1}^{D} \left(\frac{1+i}{1+r}\right)^{d-1}$$

Where:

TDCapital	=	Capital cost of the investment in year y. Note that the capital cost should be entered in the year that the expenditure stream is committed, which is likely to occur before the in-service year. The costs are lumped together to the commitment date, rather than the construction dates. However, if the project is structured such that there are major work stages that could be deferred separately, then each of the stages of work could be entered as a separate lump sum corresponding to each independent commitment date. Similarly, if there are multiple projects that have different commitment dates within the analysis horizon, each of those projects could be entered as independent lump sum values.
RECC	=	Real economic carrying charge. $RECC = \frac{(r-i)}{(1+r)} \frac{(1+r)^n}{[(1+r)^n-(1+i)^n]}$
RRScaler[y]	=	Revenue requirement scaling factor to convert direct capital costs to revenue requirement levels in year *y*. The scaling factor reflects the cost impacts of factors such as taxes, franchise fees, return on and of capital, administrative overhead, and general plant costs. The scaling factor can also vary with the utility book life of each asset.
ΔO&M	=	Incremental annual cost of O&M associated with the investment
i	=	*Inflation for T&D equipment*
r	=	*Discount rate (WACC)*
n	=	*Deferred Asset's life*
D	=	*Total years of deferral*

Table 2: Example Discrete Deferral Results ($millions)

Item	Variable	Low	Med	High
Investment Cost	TDCapital ($M)	$8.00	$10.00	$15.00

	RECC	5.25%	5.25%	5.25%
	RRScaler	150%	150%	150%
Incremental O&M	ΔO&M ($M/yr)	$0.20	$0.30	$0.40
One year Deferral	**SavingsOne ($M)**	**$0.83**	**$1.09**	**$1.58**
Two year Deferral	**SavingsTotal ($M)**	**$1.62**	**$2.12**	**$3.08**

One year savings based on reductions of 2MW to 4MW, during the hours of …
Two year savings based on reductions of 4MW to 8MW, during the hours of…

Discrete Savings per kW

DiscreteperkW = SavingsTotal / MWNeed * 1000

Where

SavingsTotal = The Discrete Deferral value for D number of years of deferral, in millions

MWNeed = MW reduction needed to attain D years of deferral

Table 3: Example of Discrete Savings per kW (based on load reduction need, not DER technology) for a 2 year deferral

Value	Variable	Low	Med	High
Two-year Deferral	SavingsTotal ($M)	$1.62	$2.12	$3.08
MW Need (Hi, Med, Lo)	MW Need (2 yr)	8	6	4
Discrete savings per kW	DiscreteperkW	$202	$353	$770

Note that there will be zero savings if insufficient MW reductions are modeled to allow deferral of the project

Avoided Cost ($/kW-yr)

AvoidedCost = SavingsOne / MWNeed * 1000

Example of avoided costs per kW-yr (based on need, not DER technology)

Table X: Example of Discrete Savings per kW (based on load reduction need, not DER technology) for a 1 year deferral

Value	Variable	Low	Med	High
Discrete one yr value	SavingsOne ($M)	$0.83	$1.09	$1.58
MW Need (Hi, Med, Lo)	MW Need (1 yr)	4	3	2
Avoided Cost	AvoidedCost	$207	$362	$790

Note that these avoided costs assume a one year deferral of the investment, and actual benefits per kW would likely vary, and potentially be zero if insufficient MW reductions are modeled to allow deferral.

4. DETERMINATION OF NEEDED LOAD REDUCTIONS

The load reduction used in the calculation of the deferral value should reflect the distribution planners' expectation of needed peak reductions. In some applications, annual load growth has been used as a proxy for the needed load reductions; in other studies, peak capacity deficiency has been used. For the intended use of locational values for targeted DER, we recommend an initial deferral value assuming a three year deferral driven by a peak load reduction equal to the cumulative three-year deficiency.

E3 has been working on locational deferral projects for over twenty years, and has observed that multi-year deferrals of at least two or three years, as opposed to single year deferrals, are generally viewed as necessary to warrant the extra effort required to implement a targeted program and reschedule a distribution project. The use of the three years allows the deferral values to reflect this reality, and allow the load reductions to reflect a combination of immediate first year deficiency need as well as load growth over the second and third years.

Related to the question of *how much* load reduction is required is the question of *when* that load reduction is required to be operational in order to achieve a distribution project deferral. In situations where the load reduction is uncertain, it may be necessary for the observed load reductions to take place before deferring a project. For long-lived DERs, that results in only a small financial impact to the utility as payments for DERs are made earlier than needed (only a financing cost of money loss). For short-lived measures like demand response, and especially demand response that pays annually for participation, the early implementation of measures before they are actually needed to avoid capacity could result in significantly increased costs for the program. For example, assume that targeted DR would pay $10,000 annually for peak load reduction. If the reduction is not needed until 2020, but the effort begins in 2017, then $30,000 in payments are made for years 2017-2019 that are not assisting the deferral of the 2020 project (other than providing some risk reduction).

We expect that the need for early load reduction will decrease as targeted implementation were to gain more experience so that distribution planners could have more certainty of the ability of the program to deliver load reductions on time. However, in the early years, we do expect that some early implementation will be necessary, and would be reasonable.

B. Determining DER measure coincidence with peak load hours

1. PEAK CAPACITY ALLOCATION FACTORS

To allow calculation of DER coincidence the peak load hours, the LNBA Tool calculates hourly allocation factors to represent the relative need for capacity reductions during the peak periods specific to each distribution area. The concept is based on the Peak Capacity Allocation Factor (PCAF) method first developed by PG&E in their 1993 General Rate Case that has since been used in many applications in California planning[11].

The peak hours could be defined in three ways:

1. Specification of months and hours. E.g.: peak period is July and August hours between 4pm and 7pm on weekdays.
2. Specification of area peak threshold. The peak period would consist of all hours with forecasted demand above the specified threshold MW. The forecasted demand would be net of all existing and forecast naturally occurring generation (both behind the meter and in-front of the meter) located downstream from the planned distribution investment.
3. Statistical specification. The peak period would consist of all hours with demand within one standard deviation of the single hour maximum peak demand for the area. In other words, the area peak threshold is calculated by the LNBA Tool based on the variability of the area loads.

The relative importance of each hour is determined using weights assigned to each peak hour either 1) in proportion to their level above the threshold, or 2) on a uniform basis. Hours outside the peak period are assigned zero weight and zero value.

The formula for peak capacity allocation factors (PCAFs) using proportional weights is shown below.

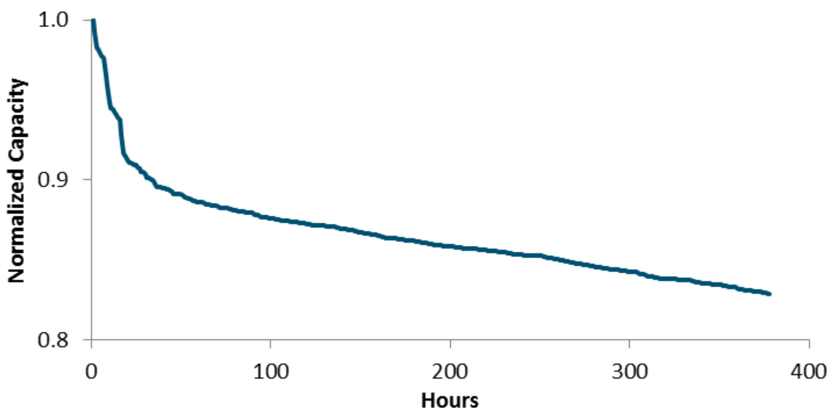
$$PCAF[yr][hr] = \frac{Max(0, Load[yr][hr] - Thresh[yr])}{\sum_{hr=1}^{8760} Max(0, Load[yr][hr] - Thresh[yr])}$$

Where *Thresh[yr]* is the load in the threshold hour or the highest load outside of the peak period.

[11] For example, PCAfs were used recently in a CPUC report quantifying distributed PV potential in California: http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

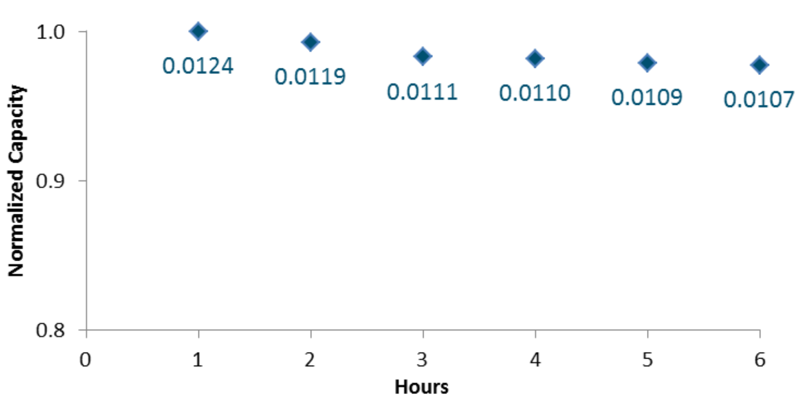
Once the PCAFs have been determined for each hour of the year, these are multiplied by the dependable output of each DER shape to determine the dependable MW contribution to peak load reductions. The following series of figures show an example of this process using the statistical peak period definition. One standard deviation from the top of the load duration curve above leaves the following hours with higher load than the threshold.

Figure 4. Example of PCAF calculation



This relatively flat load duration curve has more hours above the threshold than other peakier load duration curves – in this case, there are 378 hours. A PCAF is assigned to each one of these hours using the formula above. The following chart shows the PCAFs for the top 6 hours of the load duration curve as an example. The number below each plotted hour's normalized load represents the PCAF relative importance to peak load reductions. They are unitless, sum to one over the hours above the threshold, and can be thought of as the weights in a weighted average calculation of a particular resource's capacity contribution.

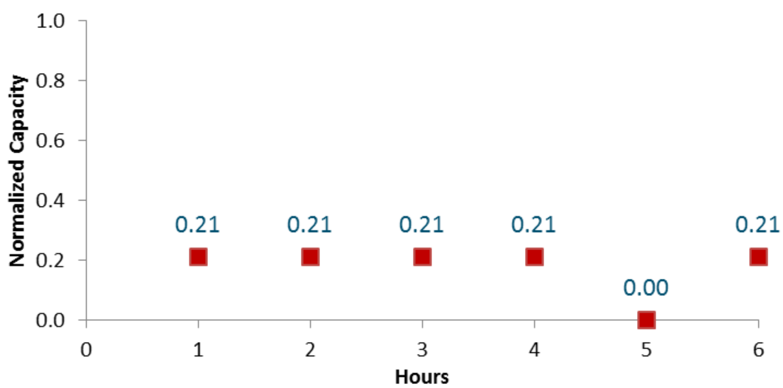
Figure 5. PCAFs for top 6 hours of load duration curve



2. COINCIDENT DEPENDABLE CAPACITY

The next step in determining a distributed resource's dependable capacity contribution to peak load reductions is to determine the coincidence of the resource's output with the highest load hours. Dependable capacity contribution is the load reduction that the utility would trust to use in planning for deferrals, and ways of calculating it are discussed in more detail in Section I.C, *Determining the dependable output of a DER measure*. The figure below shows example hourly normalized dependable load reductions (DLR_h) for a portfolio of commercial air conditioning (AC) energy efficiency (EE) resources in the 6 highest load hours. A normalized capacity of 1 represents the maximum load reduction achievable over the previously installed AC technology. These represent the dependable output of the measure - what the utility can count on in each hour to reduce load.

Figure 6. Hourly dependable capacity factors for EE output during the 6 highest load hours



To calculate the dependable MW contribution of the EE measure, the following formula is used:

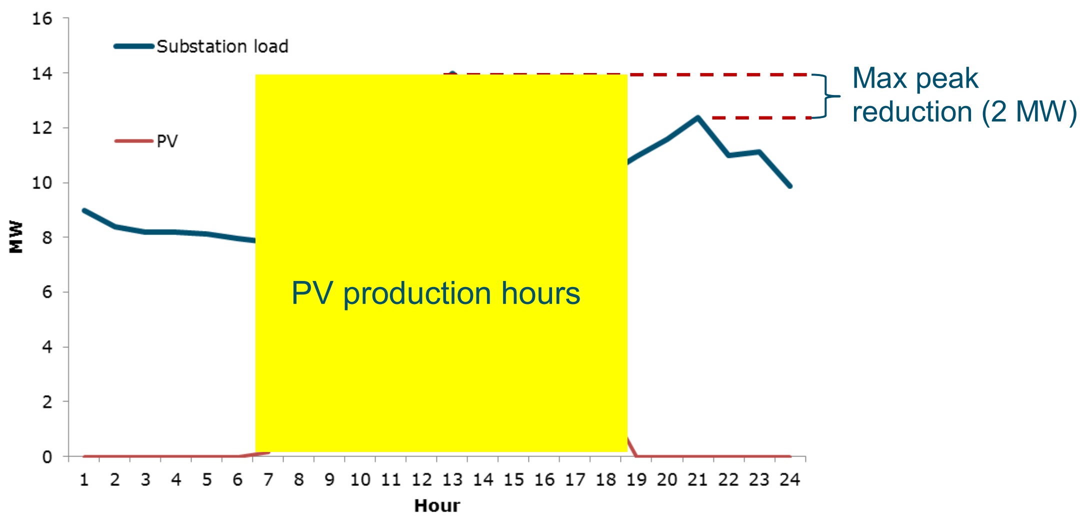
$$DepMW = \sum_{h \in (H | L_h \geq threshold)} DLR_h \times PCAF_h$$

The sum is performed over the hours in the total number of hours in the year (H) in which the load (L_h) is greater than the threshold (378 hours in the example). 20.5% of the EE measure's maximum capacity impact qualifies towards load reductions. Therefore, of the maximum capacity impact of a portfolio of new AC units of 1 MW, only 205 kW is counted towards deferring the distribution investment based on the combined effects of the distribution circuit load shape and the load shape of the DER. This produces a reasonable estimate of the dependable capacity or load reduction of the DER resource that can be used in planning and valuation models.

3. DYNAMIC NATURE OF PCAFS

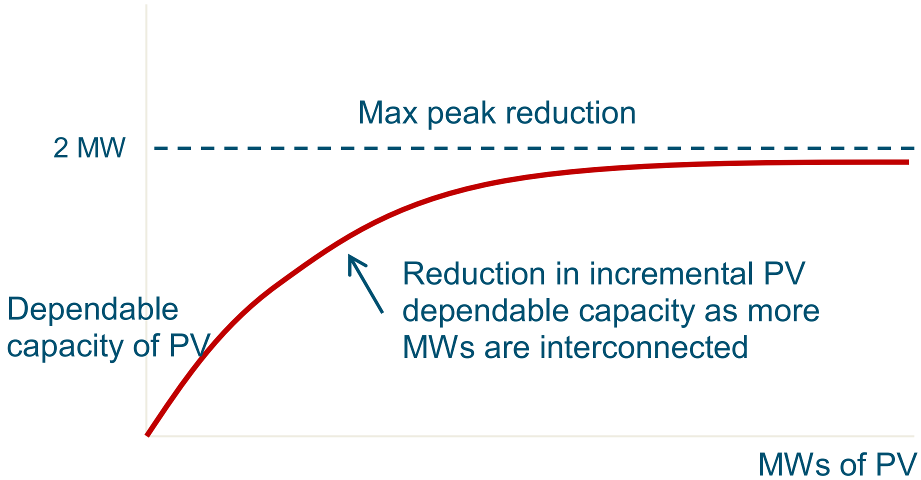
Note that as the load changes with load growth and DER implementation, the PCAFs will change. This is shown in the following example where the deferrable investment is at a substation. In this example PV is installed below the substation. The shape of the aggregate PV below the substation is shown below the substation load curve. As the level of PV increases, the daytime peak is reduced. However, there is a point where further increases in PV may reduce the the daytime peak but will not reduce the peak load at the substation because of the evening peak is higher than the day time net peak.

Figure 7. The limit to peak load reductions



In this example, the effectiveness of standalone PV at reducing the peak diminishes as the peak is shifted away from the middle of the day, approaching an asymptote at the maximum peak load reduction (2 MW in the example). This is shown in the following figure.

Figure 8. Diminishing marginal dependable capacity of standalone PV



This effect is prominent with daytime peaking DER resources such as PV, however all DER measures have interactions with the load shape, and each other, that may result in diminishing capacity returns. DER resources can also complement each other, offering more capacity together than either one can alone. PCAFs must therefore be updated whenever the load shape, net of DER output, changes significantly. This is particularly true when calculating local distribution capacity benefits, because the DER measures added to reduce peak load may be a significant fraction of the total load.

Note: The complexities of dynamic PCAFs are important for a complete understanding of the interaction of DER and distribution needs. However, it remains unclear at the present whether such effects will be modeled in the Demo B projects and the associated LNBA tool.

4. REFLECTING THE IMPACT OF ALREADY INSTALLED DER ON THE PEAK HOUR RISK

The next section discusses in detail the ways to model the dependable output of DER. The greater the number of DER measures installed, the closer the dependable output is to the expected output, but also the higher the risk of variation for weather sensitive DER. These facts raise the question of whether the dependable output for DER should only be considered for incremental DER, or should also be considered in determining the impact of existing installed DER on the hourly peak period loads used to develop the PCAFs.

Net approach

The standard approach is to use area demands that are net of historical DER. We refer to this as the "net" approach. The net approach is appropriate when there is a relatively low amount of

DER in an area, or that DER is consistent and predictable in its impact on the area. The net approach involves calculating the coincidence of the dependable capacity shape for a marginal DER addition with the net load shape (net of previously installed DER measures). Using this method, the risk of not meeting load reductions associated with previously added MWs of DER is not captured. At higher penetrations of weather-dependent DER in a local area, particularly one with not much geographic diversity, a single year's net load shape may not be enough data to base capital planning decisions on because the uncertainty around previously installed DERs will not be factored into them.

Gross Approach

The alternate approach is to use area loads that are reconstructed to reflect what they would have been without DER and then subtract out the dependable (not historical) amount of existing DER output and demand reduction. We refer to this as the "gross" method because it requires a reconstruction of total customer usage prior to reductions from DER. This method would incorporate the risk criterion (i.e. the percentile, or other risk metric) into the contribution of all DER towards peak load reductions. This option is better capable of reflecting the risk of the entire installed DER portfolio of not providing expected peak load reductions – a risk level that may be significant at high penetrations of weather-dependent DER in low geographic diversity regions.

The gross approach is the more conservative option, it is more appropriately applied across all geographic levels of the system from line segment up to system level since it incorporates changing amounts of geographic diversity, and the first approach is inconsistent since it only applies a risk derate to the marginal kW of DER and not to the existing installations. However, there will still be some geographic diversity effect captured in the first method that is reflected in the load shape of the DER resources.

The gross approach is also more data intensive, requiring knowledge of all existing DER installations down to the smallest geography considered in the model including their load shapes. This level of data is unlikely to be available system wide. At lower levels of DER penetration, the first approach using the net load shape will approximate the second most closely at lower DER penetration levels. As levels increase, the risk associated with the existing resources in delivering expected capacity reductions will also increase.

Whether gross load or net load is used in the analysis depends on the data availability on the particular part of the network being studied and the amount of weather sensitive DER already installed in that part of the network. *The method(s) that is(are) used for the Demo B projects are unclear at the time of this writing.* In either case, whether Net or Gross approaches are used, the objective of the analysis is to estimate the avoided distribution costs impact of incremental DERs in a particular location.

C. Determining the dependable output of a DER measure

As mentioned above, the ability for DER to defer a distribution investment depends upon the coincidence of the DER with the distribution area peak needs, as well as the dependability of those DER reductions. The prior section's discussion of PCAFs addressed the coincidence of DER. This section addresses the dependability of DER. Dependability of DER is typically a low impact issue when looking at system-wide DER implementation because of the large diversity offered by large numbers of installations. Expected DER output is generally sufficient for estimating system-wide impacts. However, at smaller local distribution areas, the installations of DER will be smaller in number and the "safety" of the joint output of large numbers of devices will diminish. Therefore, the dependability of DER is a more important factor for smaller local distribution areas. In addition, DER that are weather dependent (such as PV) will be subject to common "failure" modes as the weather could impact all units in an area simultaneously. Therefore, the dependability of weather sensitive DER (both future and existing) is important as the penetration of those DER in an area increases.

The dependable output of a DER measure varies by the acceptable risk level for an area. For example, a planning rule could be to accept a level of DER output that the DER measure is at or above more than 97% of the time during peak load hours. DER measure output can be derated to meet the defined planning criteria. The derate is determined by several factors:

1. Whether it can be reliably called or controlled during peak load hours,
2. what the outage rate of the measure looks like,
3. in the case of renewable generation, what is the uncertainty around the output,
4. the geographic diversity and number of installed measures, and
5. the impact of a circuit outage on the ability of the DER to perform.

These factors influence the measure impact/production shape and the derate to a greater or lesser extent. For example, energy efficiency is not 'dispatched', but is built into the infrastructure of the building or building appliances. However, energy efficiency measures tend to be installed in large numbers, reducing the uncertainty around its output and converging on a relatively low derate. Likewise, measure impact/production shapes should reflect the diversity of installing a portfolio of new systems across customers, capturing the effect of many systems contributing at the same time to load reductions. DR, on the other hand, must be controlled in the absence of a strong price signal. Estimating the derate factors comes from experience over time with installed measures. Assuming the outages reflected in the derate are uncorrelated with time of day or year, the derate can be uniformly applied to an hourly measure impact shape. This is the dependable measure output.

An alternative to calculating a weather-dependent DER derate directly (for example, in the case of PV), a dependable output shape can be determined. First, find the distribution of PV output in each hour and season. These can be formed from the aggregate output of all weather-dependent DER below the deferrable investment on the distribution system. From these distributions take the percentile corresponding to the planning rule appropriate for the area. For example, if 97% reliability is required, the model will take the 3rd percentile of each hourly and seasonal distribution. The result is a level of output from PV that in each hour of the year, PV would be expected to produce at or higher than for 97% of the time. This is the dependable PV measure output. The advantage of using this method is that for investments with very little geographic diversity in the region electrically downstream, the dependable MWs in each hour from weather dependent DER will be low because the shape without diversity benefit is more likely to be strongly affected by cloud cover etc. Conversely, investments with a lot of geographic diversity downstream will have relatively high dependable MWs in each hour because of the diversity benefit to the aggregate shape of the weather-dependent DER resource.

The dependable output of dispatchable resources depends on them being dispatched for local T&D capacity benefits. However, whether they are used for T&D deferral or not will depend on the value to the customer of T&D deferrals vs other value streams such as system capacity or ancillary services. The output of dispatchable DERs may be partially or fully derated if they are dispatched for another purpose. Only DER with contractual obligations to prioritize T&D functions will receive local T&D capacity benefits in the model.

1. MODELING OF DISPATCHABLE RESOURCES

The dependable output of a dispatchable resource is dependent on the dispatch used. These resources need to be dispatched for distribution benefits for dependable deferrals. If dispatched for system benefits, they may need to be significantly derated for distribution deferrals – particularly if the local distribution load shape is very different from the system load shape, or if storage is dispatched for other value streams such as ancillary services. Programs for an effective distribution deferral dispatch regime for DR and storage are beyond the scope of this framework. However, one method could include contracted utility control of storage during only high distribution load hours, and leaving the storage device to operate for highest value at all other times. Essentially a call option on the DER with a strike (trigger) set by distribution operations based on local reliability assessments.

When DERs are dispatched for distribution benefits the constraints on dispatch, and the uncertainty on load levels when the dispatch calls have to be made, factor into calculation of the DER dependable capacity contribution. For example, both storage and DR must be dispatched ahead of time based on forecasted loads. The forecast error determines the level of coincidence between storage and DR with the peak hours. There are further constraints to consider. For example, DR may only be called a certain number of times per year, and both storage and DR have limitations on the length of their discharge periods.

THE LNBA Tool will model the dispatch of DERs using perfect foresight under two different program options: first is a customer controlled dispatch against customer rates, with an optional utility call for local or system capacity benefits; second is a utility controlled dispatch against utility energy prices, capacity and T&D needs. These dispatch regimes will be subject to the technical constraints of the resources being modeled. Demand response will be dispatched assuming perfect forecasting, and capturing the effects of limits on annual calls, and length of discharge period. Perfect forecasting overestimates the effectiveness of dispatchable DER. However, it can be combined with a user inputted derate to account for that. The derate can be set by the utilities in future applications of the framework to approximate the effect of uncertainty. Dispatches for DERs will be done for a single year.

Avoided Costs from DERAC

The DERAC model will be replaced by an Avoided Cost Model (ACM) that is currently being updated. A draft ACM was made available to stakeholders on June 1, 2016, and final model is scheduled to be released in the beginning of July 2016. The following avoided cost components will be transferred from the ACM into the LNBA Tool to allow for DER resources to be evaluated with a full set of avoided cost values.

- Generation system capacity avoided cost
- System energy avoided cost, day ahead market, net of embedded CO2 costs (not LMP values).
- Ancillary service costs (included as a percentage adder to energy prices)
- Energy losses avoided costs (for delivery to secondary voltage)
- CO2 costs (embedded in energy market prices, but separated out for reporting purposes)
- RPS adder costs (cost of the above market price of renewables multiplied by the percentage of retail sales that must be met by RPS qualified resources).

The costs are generated hourly, and forecasted out for 30 years. The hourly variation in avoided costs are based on 2015 historical energy prices and forecast changes in market clearing prices due to increased renewable generation serving the state. Historical energy price shapes could be updated to account for the increase in renewables and in particular as a result of the increase in solar penetration.

Avoided costs outside of DERAC

D. Flexible RA

The LNBA team has identified two methods for including flexible RA in the model. A preferred method has not yet been selected.   One option is to calculate the flexible RA impact of a DER by taking its output change over the three-hour period starting in the hour indicated in the table below (from the 2016 Flexible Capacity Needs Assessment (FCNA)[12]) for November (the month with the highest 3 hr ramp):

Table 5: 2016 Forecasted Hour in Which Monthly Maximum 3-Hour Net load Ramp Began

Month	Starting Hour	Month	Starting Hour
Jan	14	Jul	12
Feb	15	Aug	12
Mar	16	Sep	14
Apr	16	Oct	15
May	16	Nov	14
Jun	15	Dec	14

This uses the expected DER profile. Adjustments for dependability (see prior section) would not be required as the flexible RA impacts accrue at the system, not the local distribution area level.

A second alternative is a user input factor that translates MW of DER into a MW increase/decrease of flexible RA requirement. This is easily done for solar, wind and EE, since these are explicitly represented

[12] https://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf

in the CAISO hourly data that is used to create a forecast of net load to determine the flexible RA requirement[13].

13 https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityNeedsTechnicalStudyProcess.aspx

Process and implementation

E. System disaggregation level

The methodology above can be applied to all levels of the electricity grid from bulk system down to circuit. Tailoring the framework to each level requires data specific to the loads and DER impacts experienced at that level. Applying the framework to a distribution planning area, for example, will potentially include several different avoidable T&D investments. DER located at the end of a feeder line could potentially have local line segment voltage impacts, substation equipment deferral, and sub-transmission deferral, in addition to avoided costs at the system level. System level non-transmission related avoided costs will be calculated using the DERAC. However, the remaining T&D avoided cost components are calculated using the above framework using the level of system disaggregation appropriate to each identified deferrable system upgrade. Below are presented examples of the level of system disaggregation and the data needs for each of the avoided cost categories identified in the introduction of this document.

F. Data requirements

The data requirements for evaluating project deferrals will vary depending on the level of granularity of the analysis. Evaluation of loads and planned T&D investments require the following:

- Information about load growth related T&D investments planned for the future, including timing, costs, and development lead times.
- Hourly loads by planning area. Depending on the granularity of the analysis, loads will be needed for the system downstream of each planned T&D investment. (loads should reflect any expected system reconfigurations). The corresponding load growth, including any potential changes in shape expected over time if available, is also needed.

Characterization of the DER being evaluated for deferral varies by technology type. The following information is required.

- Dispatch constraints for dispatchable DER. The notification time and discharge period are required for DR and storage. Additionally, the maximum number of calls on DR is needed.

The level of system disaggregation needed is dependent on the specific avoidable investments identified. An example is shown below for the first category – avoided sub-transmission, substation and feeder capital and operating expenses.

1. EXAMPLE DATA NEEDS FOR AVOIDED SUB-TRANSMISSION, SUBSTATION AND FEEDER CAPITAL AND OPERATING EXPENSES

Example: a new transformer bank at a substation identified as necessary to meet future projected load growth.

Grid disaggregation level: the substation and all loads and DER electrically downstream of the substation.

Data required:

- Aggregated load data from electrically downstream of the substation
- Aggregated DER impact shapes from all non-dispatchable DERs installed downstream of the substation (to allow determination of the weather sensitivity and aggregate dependability of both existing and incremental DER in the area). Hourly output shapes for potential incremental non-dispatchable DER that are weather matched to the load data. For EE these include end use specific impact shapes. For PV, as much data as available from all geographically diverse PV locations downstream of the project is important to develop dependable capacity contributions. Capturing the diversity effect becomes more important as the geographic area downstream of a project becomes larger, such as at sub-transmission level.
- Aggregated dispatchable DER technologies and the tariffs/programs used to operate them

G. Incorporation into Utility Planning Processes

The LNBA Tool is designed to satisfy the requirements of Demo B Modeling, as well as provide a learning platform for the utilities and stakeholders to become experienced with the LNBA needs and opportunities. The LNBA Tool is a "research tool" and not a "production grade" tool that could be integrated efficiently into utility planning processes.

While developing the specifications for the LNBA Tool, the team has considered some of the issues that could arise with the implementation of the methodology into the utility planning processes. While the list is not extensive at this point, the issues would include the following:

- **Project identification and lead times.** Projects will need to be identified early to allow sufficient time for DER implementation. The development lead time on T&D investments determines the point at which demonstrable load reductions must be made to defer an investment. This may correspond to the time at which equipment needs to be procured to complete construction of a T&D facility on time. The demonstration criteria may include either all required load reductions to be demonstrated, or some fraction of load reductions. Project lead time may decrease, or the demonstration criteria may change over time as the utilities gains more experience with DER programs.
- **Project Cost Estimates.** Project costs will be necessarily vague and generic for projects planned for many years in the future. Deferral plans should be updated every year to reflect more accurate cost estimates as project installation dates become closer and specific project plans are developed.

Appendix C – PG&E's Proposed Demo B DPAs

The two DPAs that are proposed to be evaluated are:

1) Chico (Urban/Suburban)
2) Chowchilla (Rural)

The locations within PG&E territory are shown in the figure below with Chico circled in Blue and Chowchilla circled in Red. General information about these two DPAs is provided in the following table as well.

	Chico	Chowchilla
Location	Butte County (Urban/Suburban)	Madera County (Rural)
Substations	10	4
Feeders	37 - 12 kV, 4 - 4 kV	20 - 12 kV
Customers	125,000	13,000
Recent Historical Peak	235 MW	155 MW
Customer Type	80% Residential, 5% Agricultural, 15% Commercial & Industrial	60% Residential, 30% Agricultural, 10% Commercial & Industrial